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Optimum Non Hydrocarbon Gas Injection Development Process and Ultimate Recovery Maximization.

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OPTIMUM NON HYDROCARBON GAS INJECTION DEVELOPMENT PROCESS AND ULTIMATE RECOVERY MAXIMIZATION

By
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Abstract

A multi layered heterogeneous reservoir was selected for this study. The integrated reservoir characterization model and the pertinent transformed reservoir simulation history matched model were quality assured and quality checked.

The development scheme was identified and selected where the pattern and completion of the wells were defined to fit the heterogeneity of the reservoir characterization model. Lateral and maximum block contact holes were investigated.

The development processes studied were mainly hydrogen sulphide, carbon dioxide, nitrogen and rich hydrocarbon gas. The Water Alternating Gas/ Simultaneous Water Alternating Gas (WAG / SWAG) processes were also assured. In addition to the main gas and WAG/SWAG processes, many miscible and immiscible EOR processes were also investigated though the results are not presented but may be referred to.

Field development options based on the development and processes schemes as well as reservoir management and long term business plans including phases of implementation were identified and assured. The development option that maximizes the ultimate recovery factor was evaluated and selected.

The main objective of this work was to define the development process that could give a maximum ultimate recovery factor of more than 70 %. This could increase the total technical reserves by 30 % over the reserves based on classical water flooding reserves. It may be said that the life of the field could be extended to be almost doubled.

The best technically development process that gives a maximum ultimate recovery factor of more than 70 % was the H_2S-WAG development process. The enriched-WAG development scheme can be designed to give an equivalent ultimate recovery factor by enriching the gas.

The N_2-WAG development process gives a relatively poor recovery factor. This is the lowest of all the Non-hydrocarbon Gas Injection (NHGI-WAG) development processes investigated.

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Nomenclature

English:

AG/RG	Associate Gas / Rich Gas
ARRT	Average Reservoir Rock Type
Bg	Gas Formation Volume Factor (BBLS/MSCF)
BBLS	Barrels
DD	Drawdown test
EOR	Enhanced Oil Recovery
EOS	Equation of State
URF	Ultimate Recovery Factor (%)
FWL	Free Water Level (FT)
FGL	Free Gas Level (FT)
FWPT	Field Water Production Total (BBLS)
FGPT	Field Gas Production Total (MMSCF)
FOPT	Field Oil Production Total (MMSTB)
FWIR	Field Water Injection Rate (MMBBLS)
FWCT	Field Water Cut (%)
FGIR	Field Gas Injection Rate (MMSCF/D)
FPR	Field Pressure (PSIG)
FOPR	Field Oil Production Rate (STB/D)
FGOR	Field Gas Oil Ratio (SCF/STB)
GOC	Gas Oil Contact (FT)
GOR	Gas Oil Ratio (SCF/STB)
G/O	Gas-Oil
GAW	Gas Alternating Water
IFT	Interfacial Tension (NM/M)
IOIP	Initial Oil in Place (STB)
IRCM	Integrated Reservoir Characterization Model
MDT	Modulator Dynamic Tester
MMP	Minimum Miscibility Pressure
M	Mobility Ratio

NHG	Non Hydrocarbon Gas
NHGI	Non Hydrocarbon Gas Injection
OIP	Oil in Place (STB)
OOIP	Original Oil in Place (STB)
O/W	Oil-Water
OWC	Oil Water Contact (FT)
OGIP	Original Gas in Place (MMSCF)
PBU	Pressure Build-Up
P-T-C	Pressure-Temperature-Component
PV	Pore Volume
RSM	Reservoir Simulation Model
RRT	Reservoir Rock Type
RST	Reservoir Saturation Tool
R (V/G)	Viscous to Gravity Forces Ratio
SWAG	Simultaneous Water Alternating Gas
SC	Super Critical
SCF/STB	Standard Cubic Feet / Stock Tank Barrel
SCAL	Special Core Analysis
TDT	Thermal Decay Time
WAG	Water Alternating Gas
WC	Water cut (%)
WOR	Water Oil Ratio
Z	Gas Deviation Factor

Greek:

ρg	Gas Density (LBS/FT^3)
ρo	Oil Density (LBS/FT^3)
μg	Gas Viscosity (CP)
μo	Oil Viscosity (CP)

CHAPTER I

INTRODUCTION

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INTRODUCTION

One main common objective for any optimum full field development plan is the maximization of ultimate recovery factor and minimization of capital and operating costs or the maximization of the techno-economical ultimate recovery factor. To achieve this, it is a normal practice to identify, assess, select, define and execute the optimum multiphase full field development option.

The ultimate recovery factor is implicitly a function of a development scheme, a development process scheme, a reservoir management plan and a business plan including a multiphase execution plan. It is explicitly a function of areal, vertical and displacement efficiencies.

The main components of the full field development option identified for assessment are summarized as follows:

- Field development scheme
  - Surface well patterns
  - Subsurface well bore patterns
- Field development process
  - EOR processes
  - Surface facilities
- Reservoir management plan
  - Production / Injection plan
  - Reservoir monitoring and reservoir surveillance plan
  - Technologies and studies plan
- Phased full field business plan
  - The available production / injection profiles
  - The recovery profiles targeting the ultimate recovery
  - Full field implementation road map
  - The economics profile based on an economical model that respects the general strategy of the organization

The reservoir simulation model used to assess the identified development options is an element compositional model. The input data of the integrated reservoir characterization model are actual data belonging to a producing reservoir in the UAE. The dependent variables that have to be identified, assessed and optimized are numerous. Advanced coupled subsurface – surface simulation models could be used to assess the variables. A strategical economical model is then used to select the optimum field development plan.

The UAE University at Al-Ain has a research program on the development of technologies to investigate and utilize the non hydrocarbon gases (NHG) and Enhanced Oil Recovery (EOR) injectants as follows:

- In 2002, a reservoir simulation study was conducted where hydrogen sulphide gas process was utilized as the EOR process
- In 2004, a research project on carbon dioxide (CO_2) utilization was conducted where lab tests, process studies and fluid properties studies were made.

Sour and/or acid gas injection EOR processes may cause precipitation of bitumen and chemical / physical reaction between reservoir fluids and rocks. These may lead to fluid, rock and rock fluid properties modifications. Presently it is very difficult to model Petrophysical properties and wettability changes and investigate these variables using explicitly the current models.

Laboratory studies are normally conducted and the effects are accordingly considered. The physical properties of the non hydrocarbon gases and the Equation Of State (EOS) used to predict these properties are of great importance.

Great care should be taken to regress the selected EOS using accurate laboratory data. The following properties for sour and/or acid gas components were calculated at pressure of 4175 psi and temperature of 250 °F, which maybe referenced in Table 1-A.

Table 1-A: Sour and/or acid gas components properties

Gas	B_g (Bbls/Mscf)	ρ_g (lbs/ft^3)	μ_g (cp)	Z
H_2S	0.39779	40.096	0.2216	0.476
CO_2	0.55209	37.833	0.06	0.65211
C_1	0.85229	8.80978	0.02144	1.00712
N_2	0.98214	13.3911	0.0275	1.150
AG/RG	0.88055	10.76356	0.02330	0.97126

CHAPTER II

OBJECTIVES

CHAPTER II

OBJECTIVES

The current work will assess and select the development options using the Non Hydrocarbon Gas (NHG) process that could give a high technical recovery factor of more than 70% for a layered reservoir with a relatively low vertical permeability of the stylolitic layers. The main objectives of this study will be as follows:

1. Revise / quality assure the reservoir characterization model that was developed and made by the author.
2. Revise / quality assure the 3-D compositional simulation model based on the above characterization model.
3. Identify and assess full field development options, based on enhanced oil recovery non hydrocarbon gas injection that achieve ultimate recovery factor of more that 70% for the oil reservoir and a plateau period of more than 40 years.
4. Select technically the optimum full field development plan for the non hydrocarbon gas injection process.

CHAPTER III

REVIEW OF THE PREVIOUS RESEARCH WORK ON THE SUBJECT

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REVIEW OF THE PREVIOUS RESEARCH WORK ON THE SUBJECT

Abed, Abdul-Latif, Almurawwi and Salem[1], built an element reservoir compositional model and used it to asses the development process of a combined sour gas and water injection. This study was a graduation project for partial fulfillment of the B.Sc Degree in Petroleum Engineering from UAE University. The following conclusions were drawn:

- After 30 years of production at specific plateau rate, the recovery factors for water injection, lean gas injection and combined sour gas-water injection were respectively 44.13 %, 36.36 % and 51.00 %.
- For a combined sour gas-water injection process, there is an optimum rate that can maximize recovery.
- All variables should be optimized simultaneously for the optimization of the ultimate recovery factor.

Van Vark, Masalmeh, Abu Al Nasr and Al-Khanbashi[2], studied the feasibility of large scale injection of sour and/or acid gas into a low permeable carbonate reservoir using element simulation model. Different recovery processes were evaluated such as water flooding, lean gas injection, sour gas injection, acid gas injection, acid gas injection after a slug of sour gas and CO_2 gas injection. The study concluded that the sweep efficiency improves with lower miscibility pressure. When applying a realistic GOR constraint, injection of acid gas could easily recover twice as much oil as is attainable with lean gas. Sour gas and CO_2 gas fall in between.

Wilkinson, Teletzki and King[3], presented opportunities and challenges for enhanced recovery of the Middle East. These processes include sour gas, acid gas, CO_2-WAG, hydrocarbon gas WAG and N_2-WAG. It was concluded that implementing timely and appropriate IOR/EOR technology in the large Middle East reservoirs will be critical to meeting future global supply-demand projections.

Shedid, Zekri and Al-Mehaideb[4], conducted laboratory investigation of initial oil saturation and oil viscosity on oil recovery by Carbon Dioxide (CO_2) miscible flooding, using actual limestone core samples and actual reservoir fluids. The tests were conducted under simulated reservoir conditions of pressure and temperature. The results indicated the following:

- The higher the initial oil saturation the higher the recovery. The application at initial oil saturation recovered the maximum oil equivalent to 98.6 %.
- The higher the oil viscosity, the lower the oil recovery by CO_2 flooding.

Zekri, Shedid and Al-Mehaideb[5], conducted a laboratory study to investigate the influence of SC- CO_2 flooding on rock, fluid and rock-fluid properties.
The following conclusions were drawn:

- SC-CO_2 flooding reduces the porosity and permeability.
- The increase of wettability of water wet system to more water-wet condition.
- Reduction of the interfacial tension (IFT) between the oil-water system.
- Water shielding of oil from contacting CO_2 had a significant effect on the displacement of oil by SC-CO_2 and the resultant miscible flood overall recovery.

Zekri , Al-mehaideb and Shedid[6], studied the effect of pressure, oil saturation, core permeability, throughput, asphaltene deposition and petrophysical properties of tight carbonates on CO_2 flooding. The following conclusions were withdrawn:

- It is clear that an optimum amount of SC- CO_2 is required to maximize the oil displacement from a specific area and this is a function of permeability, pressure, temperature, and probably the flow rate.
- Measuring the asphaltene concentration in the oil before and after CO_2 flooding indicated a change, because of the conditions of the experiments. It was difficult to detect directly the asphaltene precipitation.
- Dissolution of calcite grains will improve the permeability but the precipitation of calcite downstream will result in reduction of permeability and consequently this may affect injectivity. However the problem is complicated in the presence of asphaltene and sulphur in the oil. Therefore, the

precipitation effect of different elements, calcite, asphaltene and sulphur should be simultaneously evaluated.

- Using very tight core samples and increasing SC-CO_2 pressure increased the total oil recovery and reduced the CO_2 requirements.
- Results from secondary, intermediate and tertiary EOR processes showed that more oil recovery could be obtained if we start flooding process at higher oil saturation and there is probably a critical oil saturation required to optimize the process.
- Displacement efficiency improves with higher permeability where at higher permeability CO_2 can mobilize oil much better and forms a larger oil bank which results in higher displacement efficiency. At higher permeability, CO_2 managed to contact more of the oil in place (OIP) and consequently was able to displace and /or extract a larger amount of hydrocarbon compared with the lower permeability core.

Shedid, Al mehaideb and Zekri[7], conducted a lab study using whole core to investigate the effect of a miscible CO_2 slug size. Slug sizes of 0.0, 0.15, 0.30, 0.45 and 1.00 (CO_2 injection) were used. The ultimate recovery ranges between 66% and 96%. The following conclusions were made:

- Asphaltene deposition has been observed in production tubes.
- The relatively high oil recovery by water flooding is attributed to good displacement efficiency in view of asphaltene deposition.
- There is an optimum slug size for a process applied in a reservoir.
- A continuous CO_2 flooding recovered 97% initial oil in place (IOIP) when 1.5 pore volume (PV) is injected and 62% IOIP when 1.5 pore volume (PV) of water is injected.

Shedid and Abed[8], conducted a reservoir simulation study to:

- Investigate the feasibility of utilizing the sour gas as hydrogen sulfide injection or simultaneous hydrogen sulfide-water injection to improve oil recovery.

- Study the influence of flow rate and mole percent of hydrogen sulfide on oil recovery.

On the basis of the reservoir simulation study of the feasibility of water, Hydrogen sulfide, and simultaneous hydrogen sulfide-water injections into oil reservoirs to improve oil recovery, the following conclusions were drawn:

- A reservoir characterization model is built using actual field data and used to develop a simulation model to study the feasibility of water, hydrogen sulfide, and simultaneous water-hydrogen sulfide injections to improve oil recovery.
- There are optimum injection rates for water and hydrogen sulfide. For this case, the optimum rate of water and sour gas may be selected to be 6 MMBBLS/D and 10 MMSCF/D, respectively, for the selected reservoir under investigation when the oil production rate was 4 MSTB/D
- The increase of hydrogen sulfide mole percent increases the oil recovery in case of sour gas. However, at relatively high mole percent, the change of recovery with the increase of H_2S mole percent is small. This may be attributed to the higher molecular weight of hydrogen sulfide in comparison to methane.
- The simultaneous injection of hydrogen sulfide and water into oil reservoir increases the oil recovery more than continuous gas and water injection processes. Furthermore, the increase of injection rate of hydrogen sulfide in the injected hydrogen sulfide-water slug increases the oil recovery.

Al Falahy, Abou-Kassem, Chakma and Islam[9] numerical simulation studies on CO_2 gas injection to investigate solutions that deal with both sour gas disposal and oil recovery with sour gas.

The following findings were indicated for miscible and stable conditions:

- Numerical results indicate that oil recovery as high as 90% can be achieved with pure H_2S.
- Recoveries were only slightly changed when a mixture of gases was used.
- The high recovery of H_2S injection was followed by mixtures of H_2S and CO_2 and methane (84%).
- The lowest recovery factor was reported with CO_2 (80%).

Al Mehaideb, Shedid and Zekri[10], conducted a laboratory study of miscible CO_2 flooding of UAE carbonate oil reservoirs and investigated the following:

- Phase behavior of crude oil-CO_2 system including PVT model setup and tuning of EOS model.
- Core flooding experiments:
  - Effect of initial oil saturations on CO_2 flooding performance.
  - Effect of reservoir pressure on the performance of CO_2 flooding.
  - Determination of optimum CO_2 slug size.
  - CO_2 reservoir fluids and rock interaction.
  - Sulfur and asphaltene deposition during CO_2 flooding.

The following conclusions were drawn:

- The developed EOS model accuracy gave 1%-5% error range.
- The oil recovery by miscible flooding is higher for higher CO_2 slug size.
- The oil recovery by SC-CO_2 is higher for higher initial oil saturation.
- The oil recovery by SC-CO_2 is higher for higher reservoir pressure.
- Higher production rate of sulfuric oil under CO_2 miscible flooding reduces permeability and porosity.

Zekri and Natuh[11], conducted a laboratory study of the effect of miscible WAG process on tertiary oil recovery. The system studied was and oil wet system. Laboratory displacement tests using various development WAG processes at a constant amount of CO_2 or hydrocarbon gas were made.

The following conclusions were stated:

- The hydrocarbon gas/water ratio is not affecting the total oil recovery.
- The CO_2 gas/water ratio is not affecting the total oil recovery of the tested sandstone samples.
- The hydrocarbon gas/water injection ratio generally has no effect on the producing GOR.

Uchiyama, Yamada, Ishil and Salamah[12], discussed the performance of two reservoirs under sweet and sour gas injection as an EOR processes in Abu Dhabi. The facilities of sour gas injection has been successfully implemented and operated. It has been concluded that the maximum total oil recovery has been achieved.

CHAPTER IV
RESERVOIR MODELING

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RESERVOIR MODELING

For a selected reservoir, an element reservoir simulation model was developed based on a transformed integrated reservoir characterization model. Before using in the current work, the integrated reservoir characterization model and the reservoir simulation model were updated and quality assured. Figure 4.0-A shows 3-D gridding system and well locations in the model.

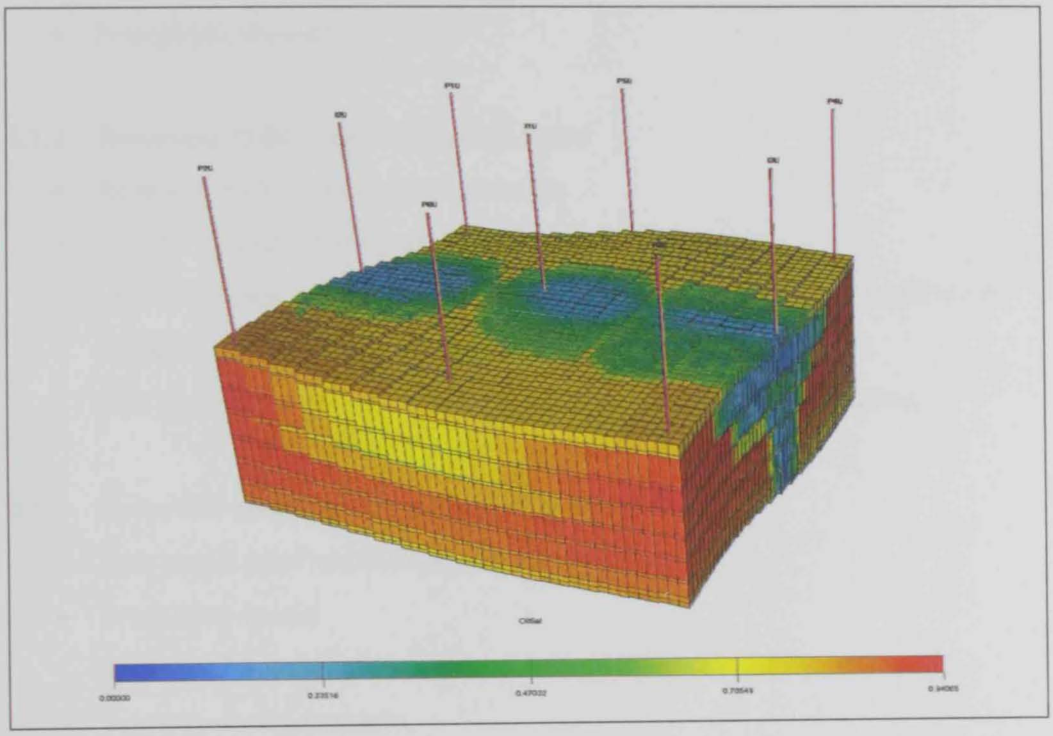

Figure 4.0-A: 3-D Simulation Model and Well Locations

4.1 Main components of integrated reservoir characterization model

4.1.1 Reservoir rock characterization model

- Geophysical model.
- Structural model.
- Sedimentological model.
- Stratigraphical model.
- Geomechanical model.
- Lab studies.
- Engineering studies.
- Petrophysical model.

4.1.2 Reservoir fluid characterization model

- Reservoir rock characterization model.
- 3-D fluid composition model.
- Phase behavior and Pressure-Temperature-Component (P-T-C) equilibrium.
- Equation of state (EOS) development including H_2O component.
- Non-hydrocarbon components will be treated without pseudoisation.

4.1.3 Reservoir rock-fluid characterization model

- Pore model and fluid distribution.
- Wettability model.
- Rock-fluid functions.
- Petrophysical parameters.
- Geochemical model.

4.1.4 Integration and final characterization model

- Rock types.
- Layering model.
- Fluid-fluid contacts.

4.2 Main Components of Reservoir Simulation Model (RSM)

4.2.1 Transformation of Integrated Reservoir Characterization Model (IRCM)

- Grid system generation.
- Validation and auditing of RSM input data.
- Initialization of RSM
  - Original oil in place (OOIP)
  - Original gas in place (OGIP)
  - Fluid contacts [Free Water Level (FWL), Free Gas Level (FGL), Oil Water Contact (OWC) and Gas Oil Contact (GOC)]

4.2.2 History match of reservoir simulation model (RSM):

- Focused models
  - Well tests
  - Pilot tests
  - Special tests

- Full Field Model
  - Well performance
  - Water Cut (WC) distribution
  - Gas Oil Ratio (GOR) distribution
  - Pressure distribution

4.2.3 Development options

- Natural depletion.
- Water injection.
- Rich gas injection.
- Lean gas injection.
- Sour gas injection.
- N_2 gas injection.

- Acid gas injection.
- CO_2 injection.
- Combination of two or more options.

4.2.4 Coupled subsurface-surface model

- Well outflow performance.
- Choke performance.
- Surface network model.

4.3 Economic model and optimization

- Economic model.
- Optimization.

Figures 4.3-A to 4.3-L show a summary of standard flow charts to develop the integrated reservoir characterization model and the reservoir simulation model.

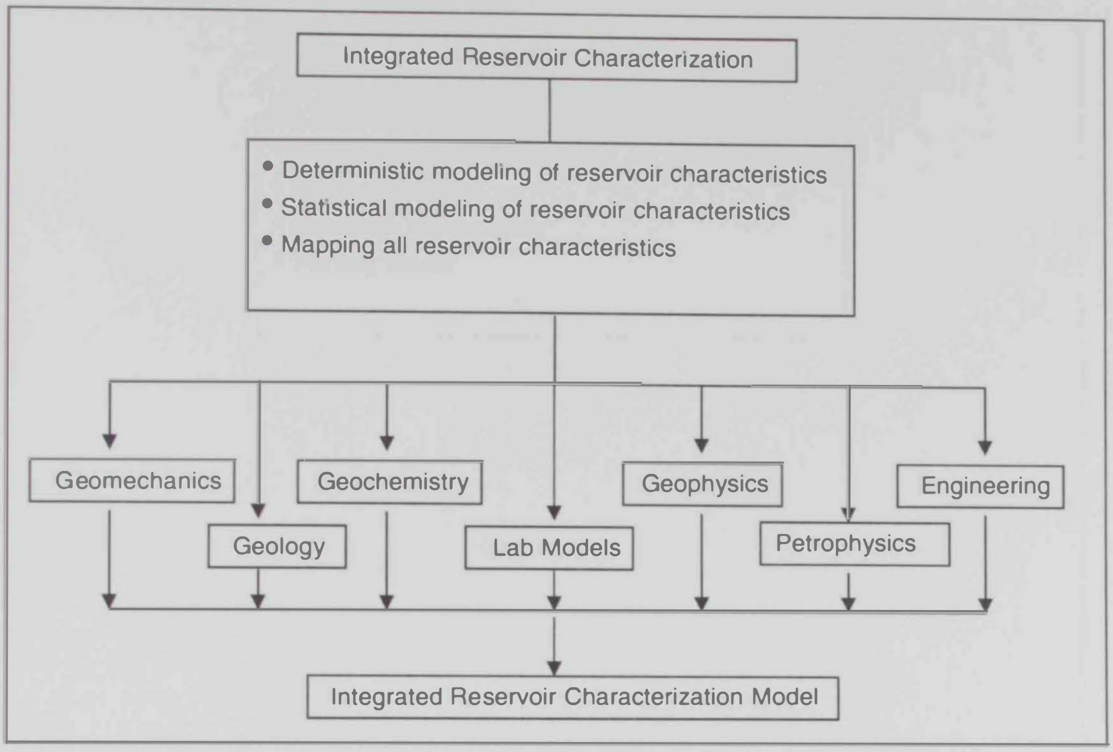

Figure 4.3-A: Integrated Reservoir Characterization Framework

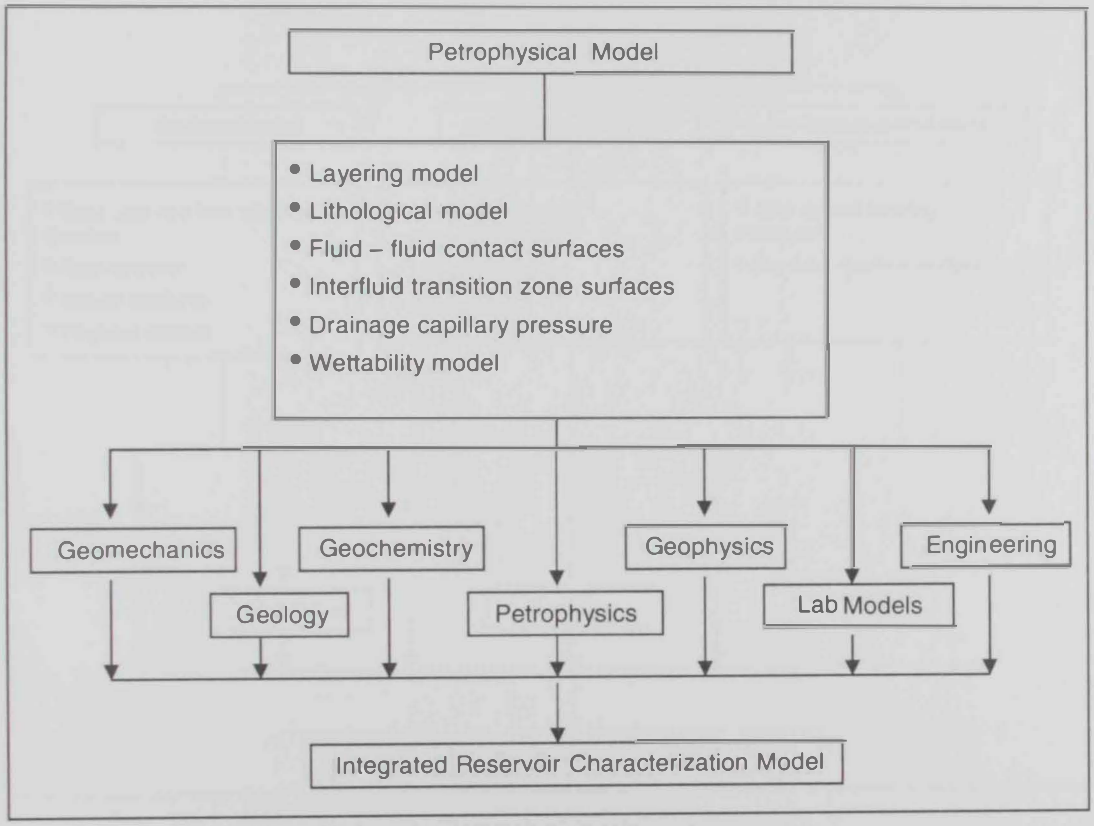

Figure 4.3-B: Petrophysical Model Framework

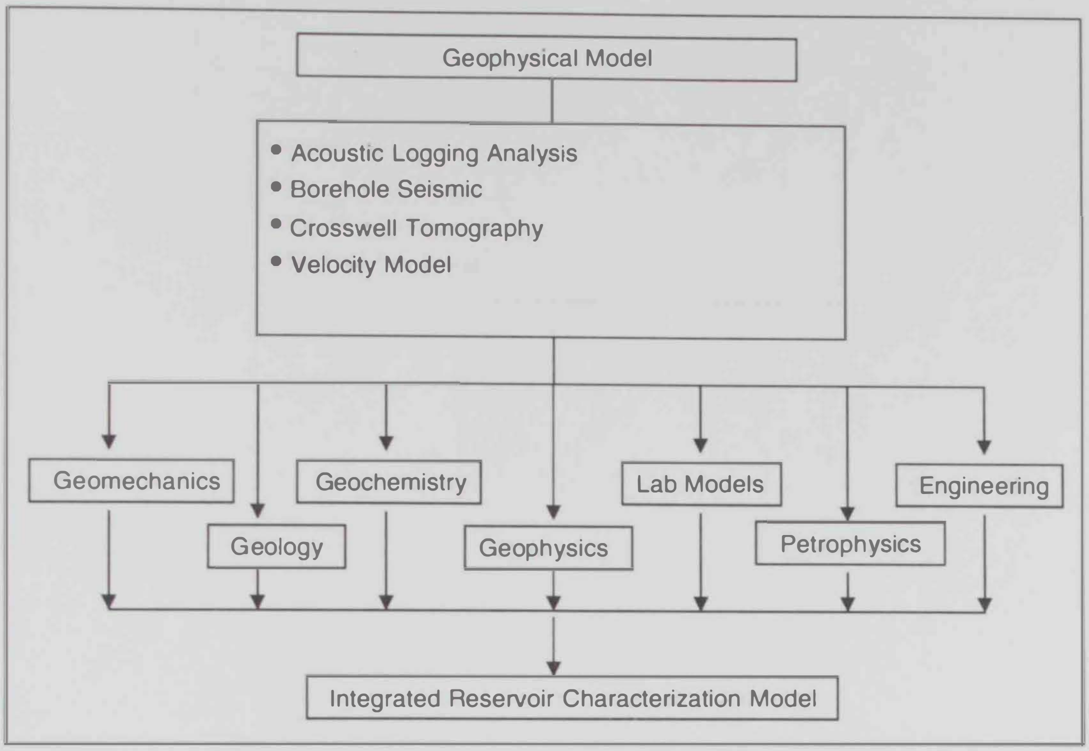

Figure 4.3-C: Geophysical Model Framework

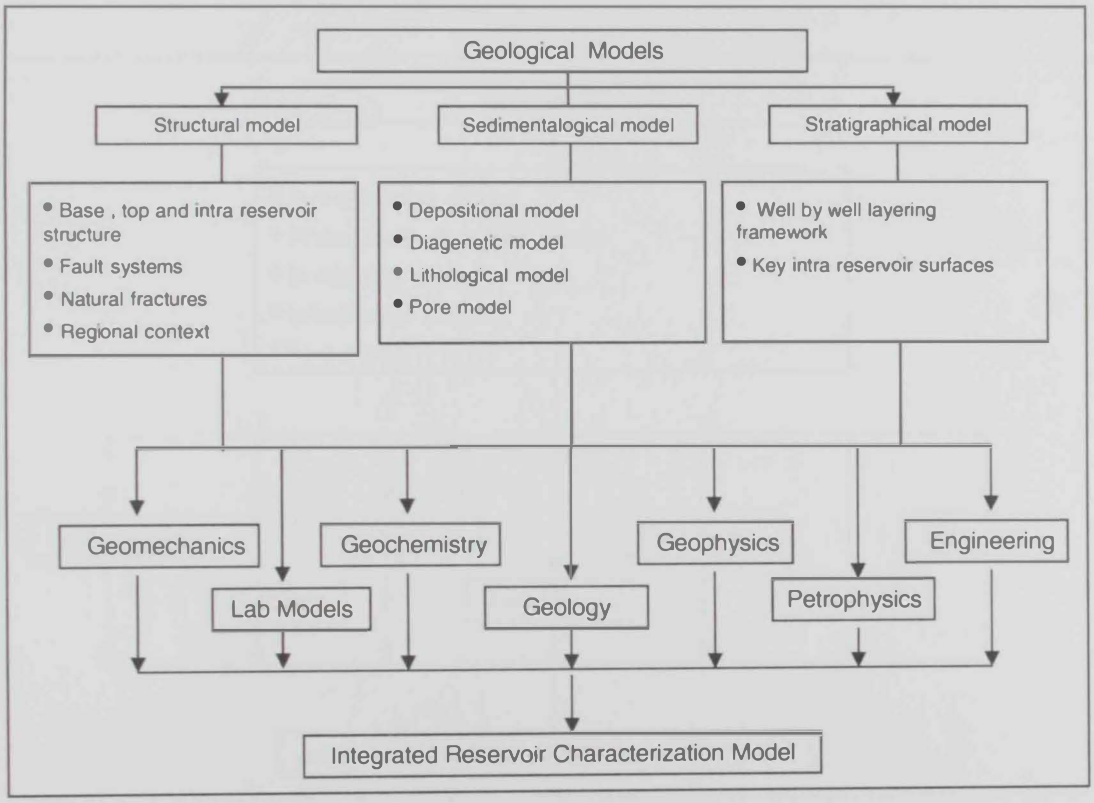

Figure 4.3-D: Geological Model Framework

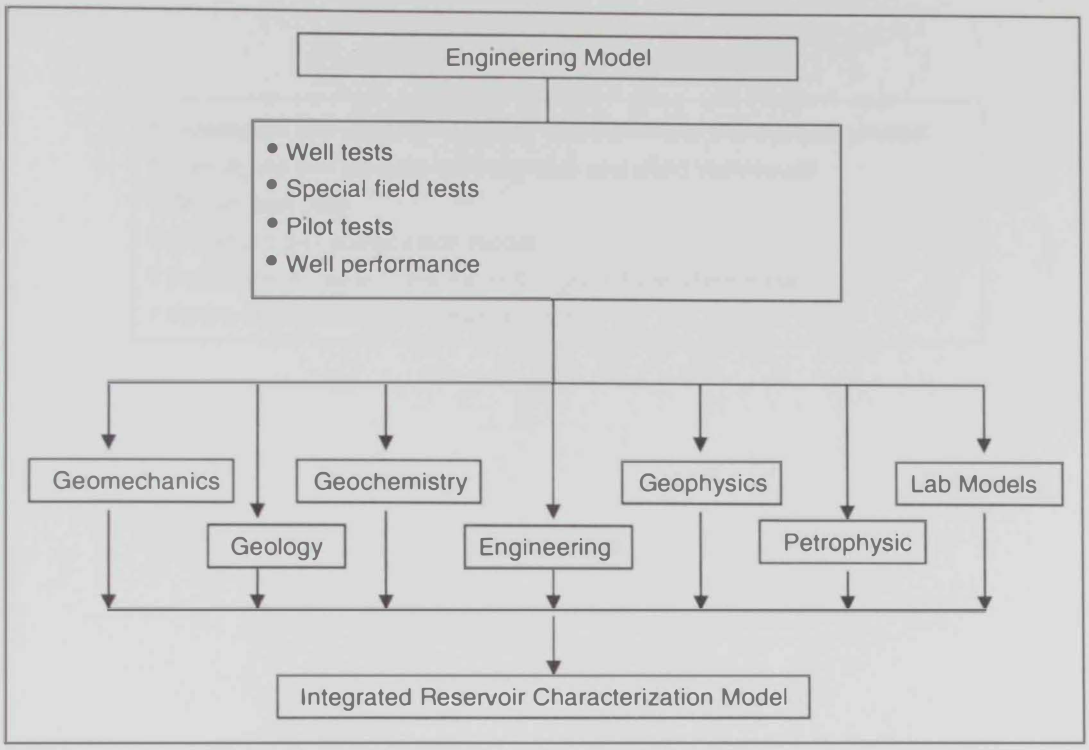

Figure 4.3-E: Engineering Model Framework

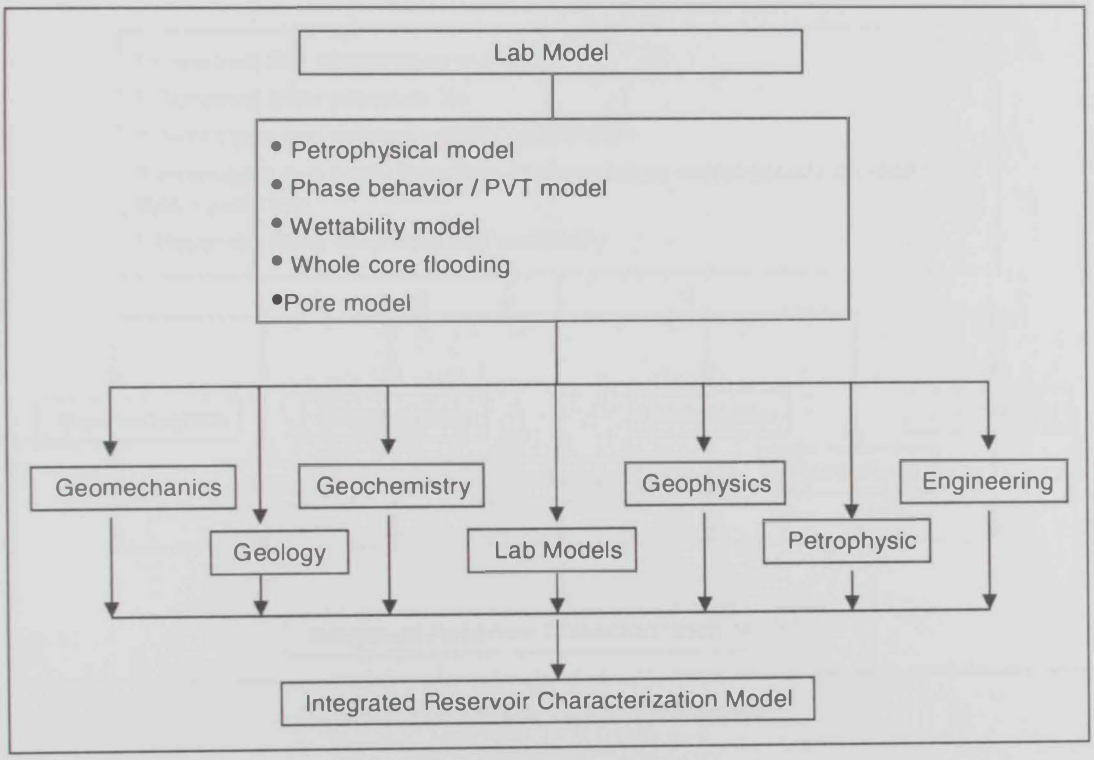

Figure 4.3-F: Lab Model Framework

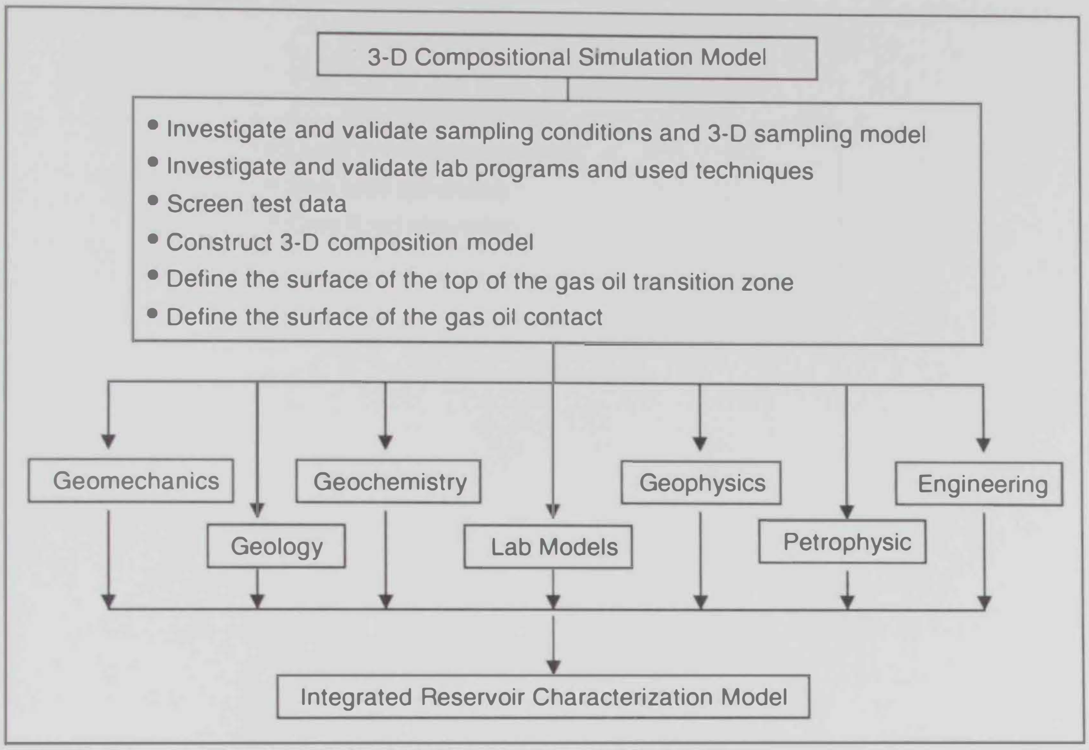

Figure 4.3-G: 4-D Compositional Model Framework

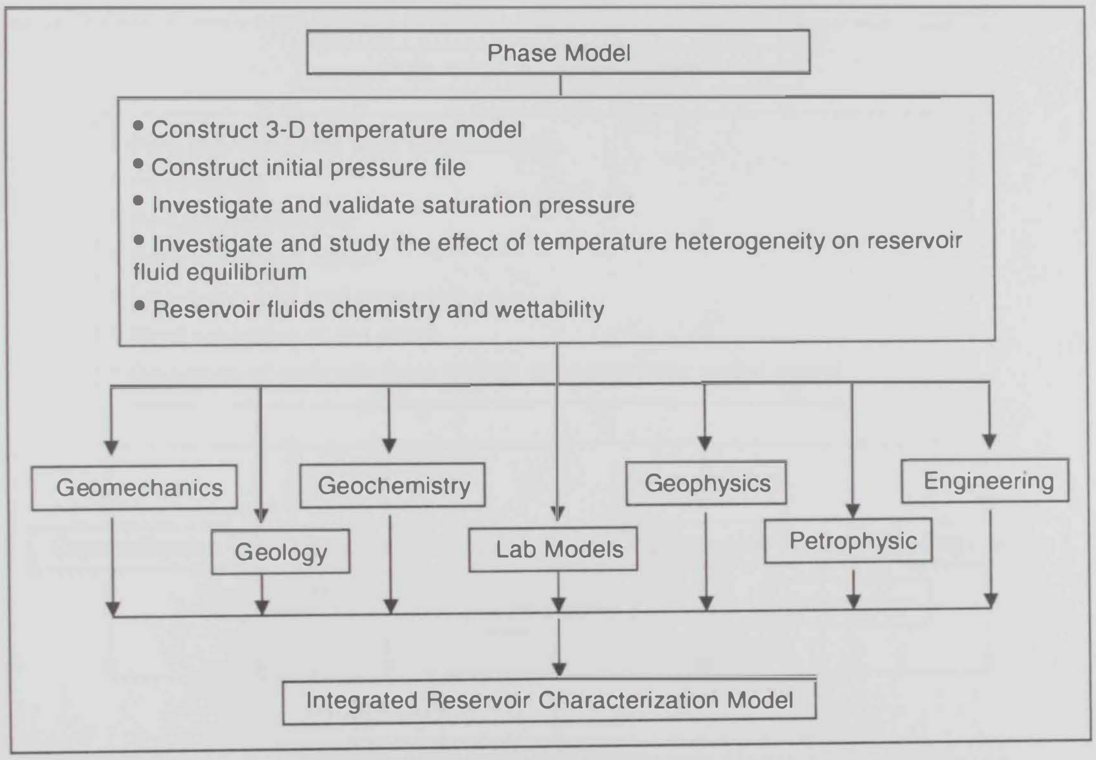

Figure 4.3-H: Phase Model Framework

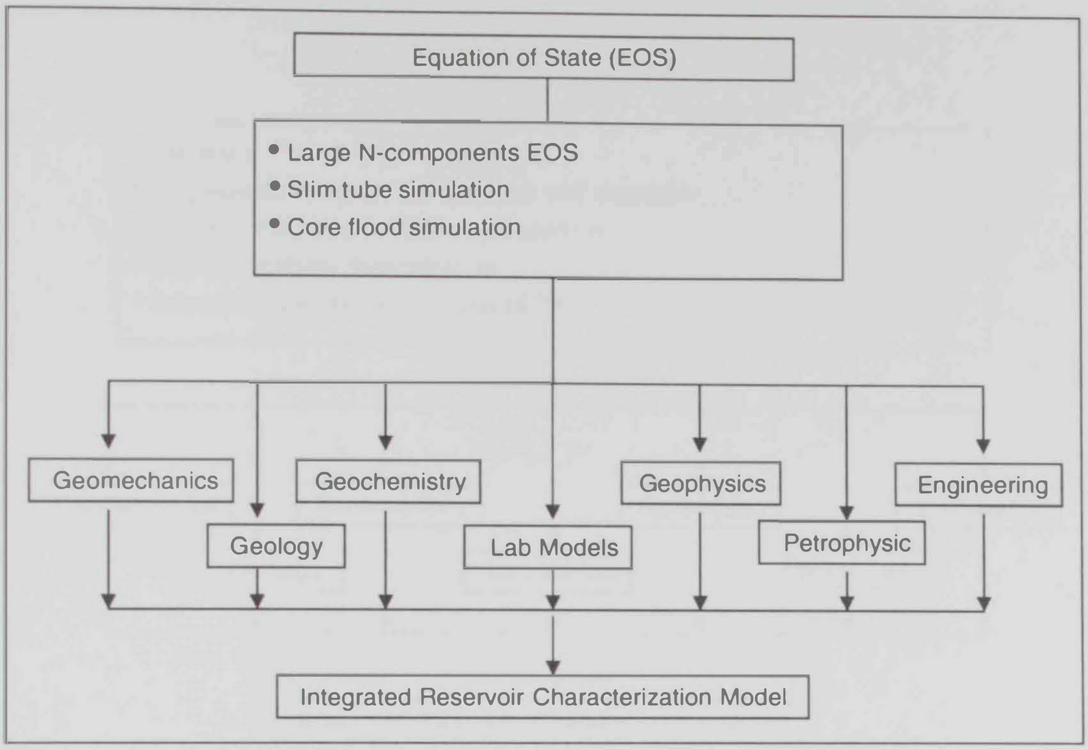

Figure 4.3-I: Equation of State Framework

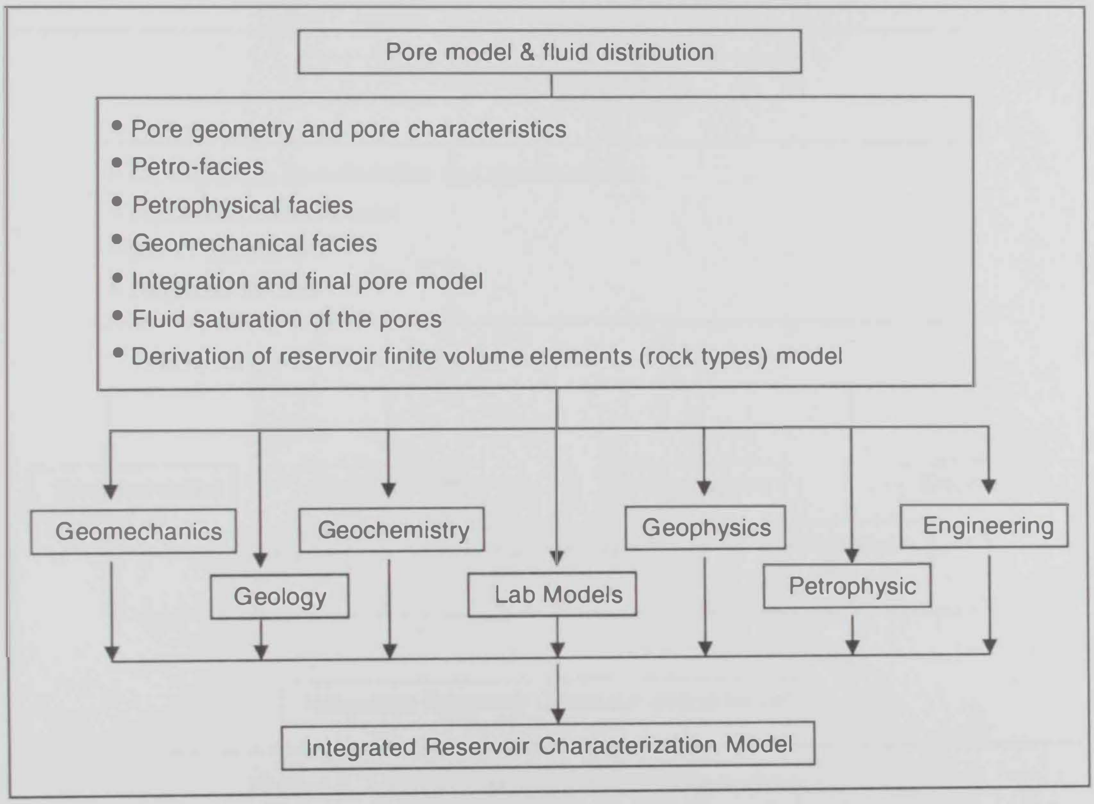

Figure 4.3-J: Pore model & fluid distribution Framework

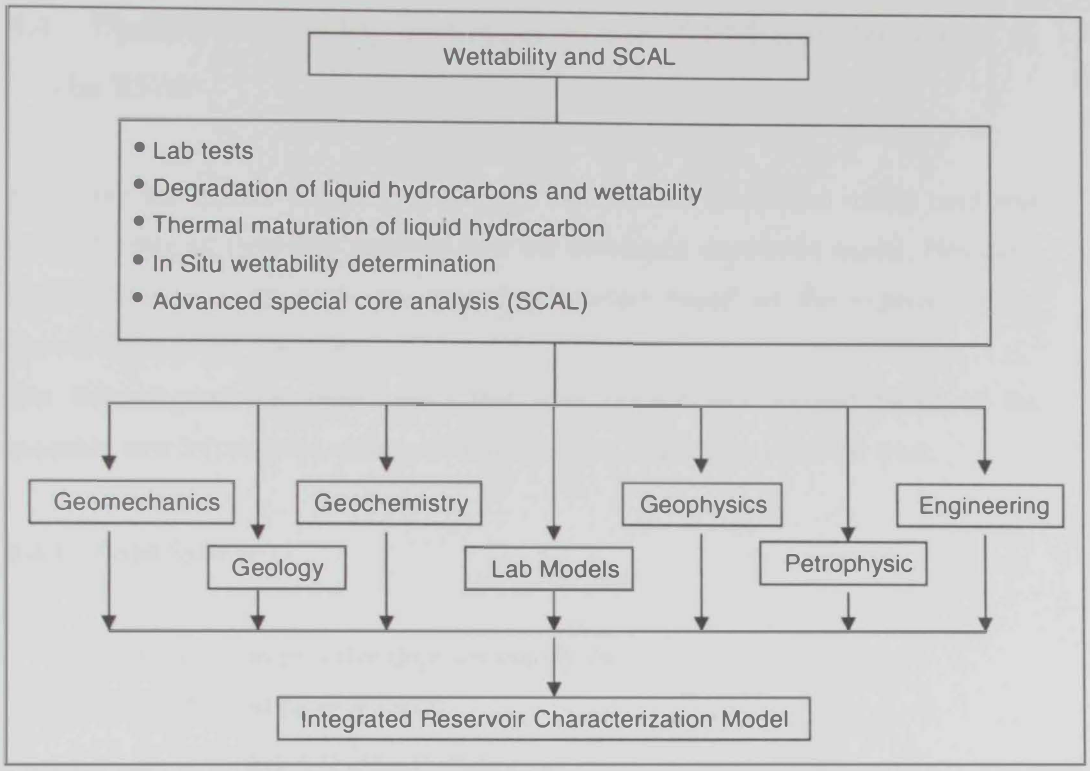

Figure 4.3-K: Wettability and SCAL Framework

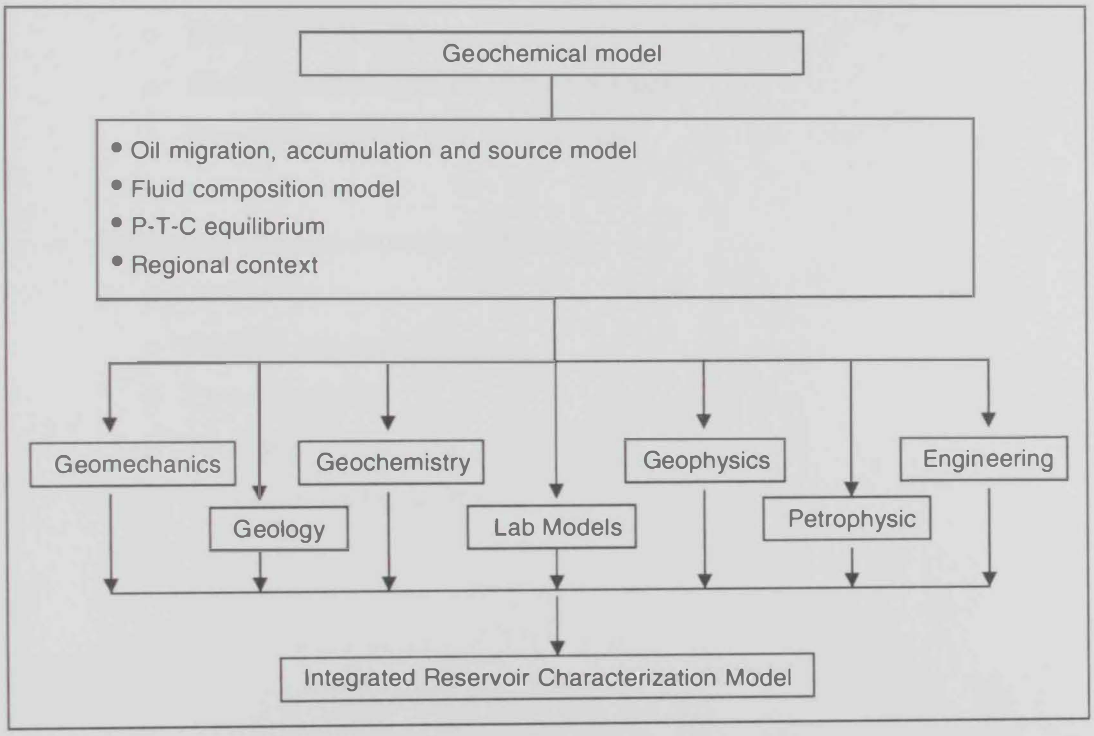

Figure 4.3-L: Geochemical Model Framework

4.4 Update and quality assurance of the IRCM transformation to the RSM

Following the applied standard procedures, the reservoir simulation model used was updated using all field data gathered post the developed simulation model. However, special attention was made on special parameters based on the experience and knowledge recently compiled.

The following are the main topics that were revised and updated based on the available new information obtained from field, lab and similar research work.

4.4.1 Grid System

- X, Y direction grid size depends mainly on:
  - Lateral heterogeneity
  - Faulting and fault system
  - Pattern and spacing between wells
  - Fluid injection scheme
  - Fluid boundaries and reservoir boundaries
  - Reservoir and reservoir aquifer sizes

- Z direction grid size depends mainly on:
  - Anisotropy
  - Faulting and fault system
  - Layering model
  - Fluid injection scheme
  - Reservoir fluid properties

4.4.2 Rock-type discriminant

A rock type is a function of all the variables of the reservoir characterization model including of course the wettability of the rock-fluid model.

The following figure shows the reservoir rock-typing and rock type discriminant:

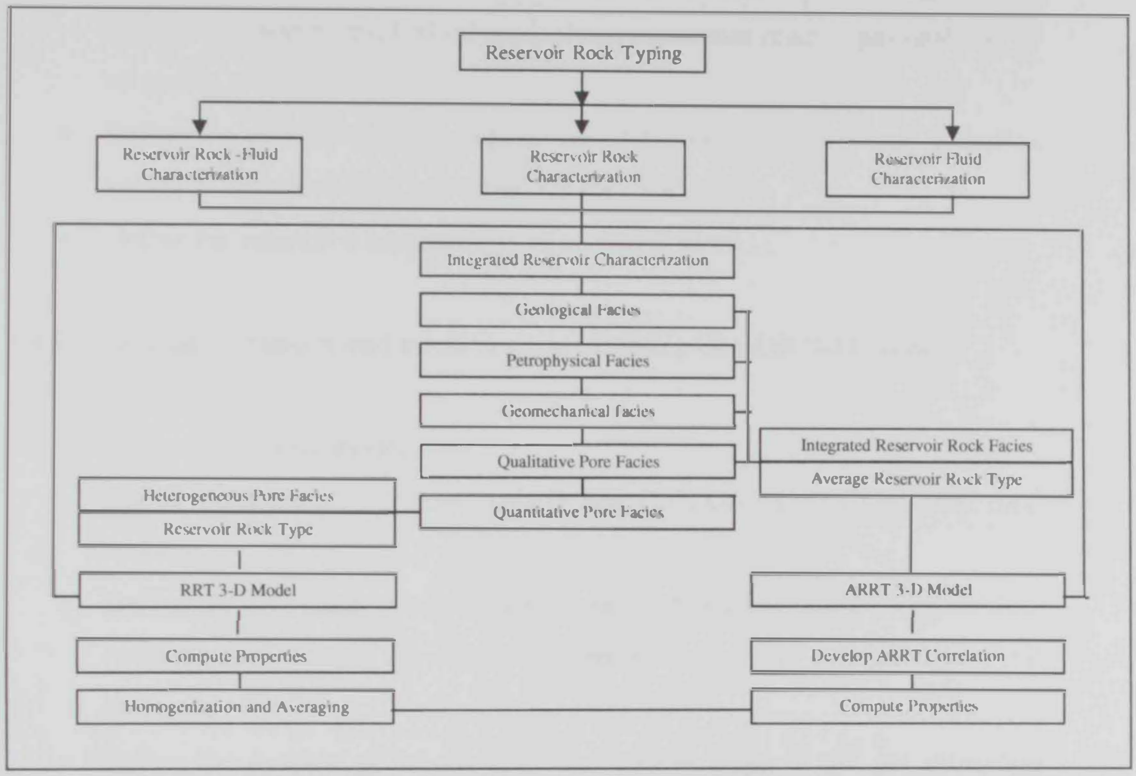

Figure 4.4.2-A: Reservoir Rock-Typing Framework

4.4.3 Scaling and averaging

- Scalar variables, namely porosity, water saturation vs. depth are weighted arithmetically.
- Tensor variables, namely permeability are weighted based on whether the flow is in parallel or in series.
- The fluid composition is volumetrically weighted.
- The saturation functions are defined for each block based on the averaged properties.

4.4.4 Capillary pressure and relative permeabilities Oil-Water (OW) system

- Define wettability model.
- Define fluid contact surfaces, namely free O/W, O/W, top of transition zone surfaces.
- Define the end point values of the saturation functions, comprising residual (interstitial) water, residual oil saturations, maximum relative permeability to oil and to water.
- Define the number of the curves based on the range of the water saturation values of each rock type as derived for the O/W system.
- Define the saturation number keys of each grid block.

4.4.5 Capillary pressure and relative permeabilities Gas-Oil (GO) system

- Define wettability model.
- Define fluid contact surfaces, namely free G/O, G/O, top of transition zone surfaces.
- Define the end point values of the saturation functions, comprising residual (critical) gas, residual oil saturations, maximum relative permeability to oil and to gas.
- Define the number of the curves based on the range of the gas saturation values of each rock type as derived for the G/O system.
- Define the saturation number keys of each grid block.

4.4.6 Fluid Properties and Equation of State (EOS)

The following flow chart shows the procedure of the EOS construction:

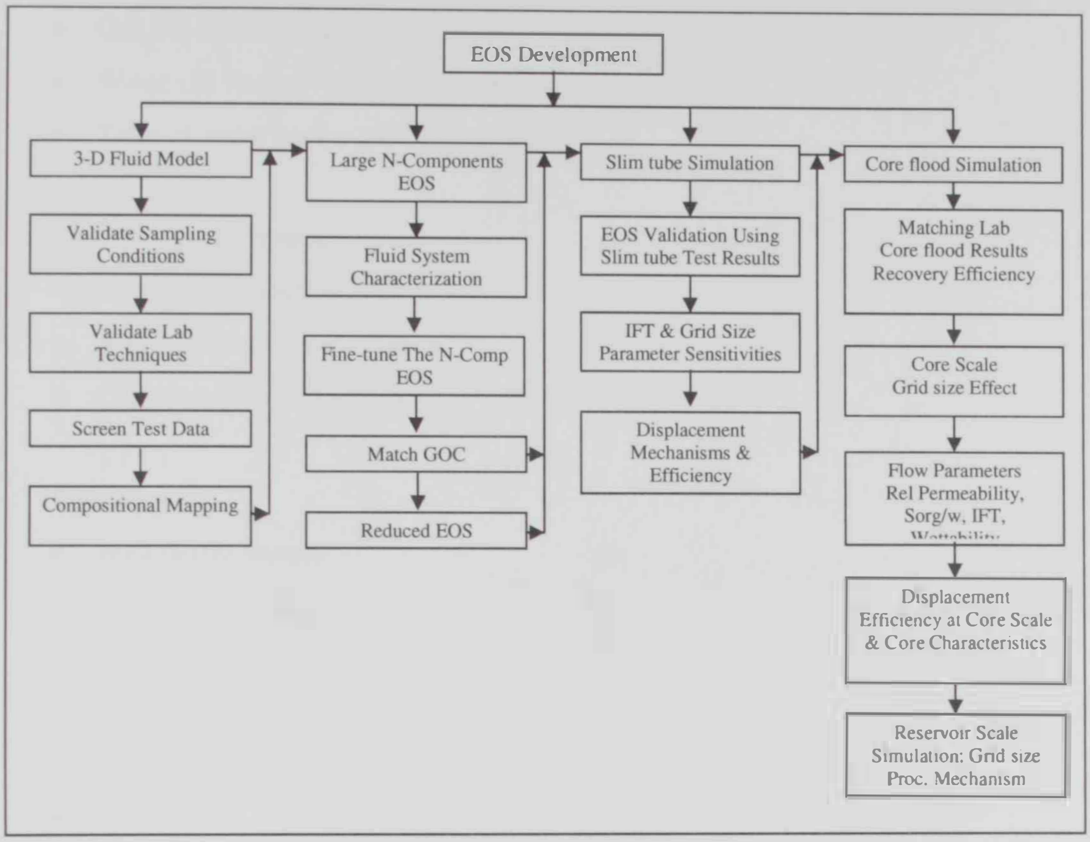

Figure 4.4.6-A: EOS Development & construction procedure

4.4.7 History Matching

Well performance

- Static and flowing bottom hole pressures.
- Gas Oil Ratio (GOR).
- Water Oil Ratio (WOR) or Water Cut (WC).
- Time of water and/or gas breakthrough.

Reservoir performance

- Pressure distribution.
- Water saturation distribution.
- Gas saturation distribution.

Pilot tests

- Well performance.
- Special field tests.

Special field tests

- MDT.
- TDT/RST.
- Pulse tests.
- Tracer tests.
- Communication tests.
- PBU and DD tests.
- Inter-well logging.

CHAPTER V

RESERVOIR DEVELOPMENT AND DEVELOPMENT OPTIONS

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RESERVOIR DEVELOPMENT AND DEVELOPMENT OPTIONS

The identification, the assessment, the selection, the definition, the execution and the operation of development options form the standard procedure for the optimization of the reservoir development plan. The main components of a development option that defines the dependent variables of the technical ultimate recovery factor could be summarized as follows:

- Development scheme.
- Development process.
- Reservoir management including production injection profile.
- Business plan including phases of implementation.

Figure 5-A shows a reservoir development plan that forms bases for a development option identification that will be investigated in the current work. As stated, the main objective will be to investigate the Non-Hydrocarbon Gas Injection (NHGI) processes within the framework of a reservoir development plan.

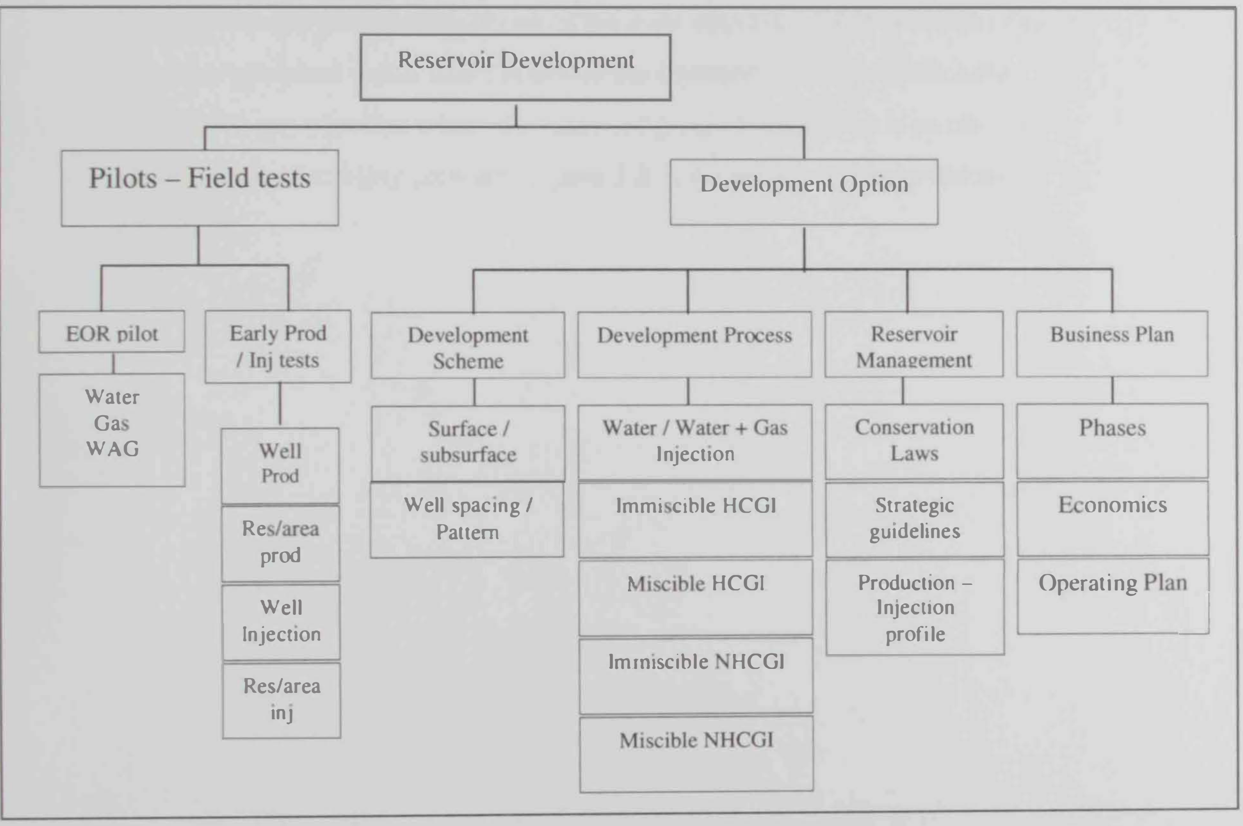

Figure 5-A: Full Field Development Plan Optimization

5.1 Development Scheme

The development scheme is a strong dependent variable of the ultimate recovery factor. It is selected to maximize the volumetric sweep efficiency. In fact, the development pattern will represent a balanced production-injection volume that will be depleted by the pattern wells.

The development schemes considered in the current work when the wells are not lateral are the 5-spot and direct line drive patterns. For lateral holes, the patterns are 5-lateral holes and direct line drive lateral holes pattern.

5.2 Development process

The main EOR processes considered to maximize ultimate recovery factor in this study are continuous NHGI, NHGI slug injection followed by water injection cyclic / NHGI-WAG and combined water and gas injection processes. Other EOR processes are considered only for reference and optimization.

Gas injection or gas flooding is one of the most important EOR processes that are commonly applied world wide. Miscible gas injection is more efficient than immiscible gas injection where the reservoir pressure should be high enough to exceed a gas miscibility pressure. Figure 5.2-A presents various gas injection processes.

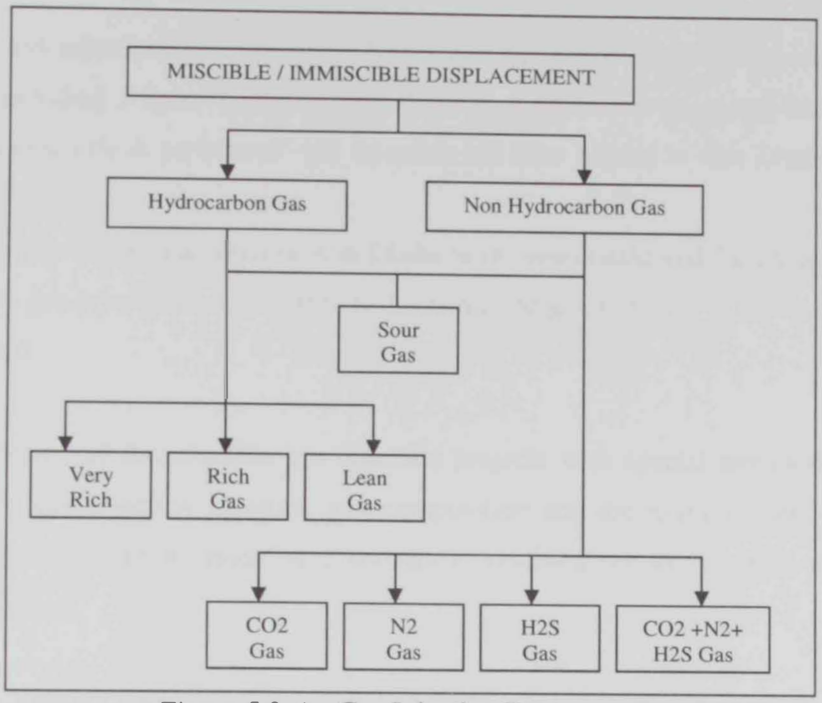

Figure 5.2-A: Gas Injection Processes

In a gas liquid system, a miscible bank is formed by either evaporation or condensation of the intermediate hydrocarbons ($C_2 - C_6$). If the major transfer of the intermediate hydrocarbons occurs by condensation from the gas, the system is known as enriched- gas or condensing-gas drive. If the major transfer of intermediate hydrocarbons is from, the reservoir oil, then the system is known as high pressure or vaporizing – gas pressure, vaporizing – gas drive process. At sufficiently high pressure, vaporizing- gas drive miscibility can be attained with lean hydrocarbon gas, H_2S, CO_2 and nitrogen.

The main source of gas for gas injection could be summarized as follows:

Table 5.2-A: Source of gas for gas injection

Gas	Source
Associated rich / lean gas	Oil and gas condensate reservoir, gas after NGL extracted from associated gas
Acid gas ($CO_2 + H_2S$)	Residue gas after sweetening
Lean Sour gas	Gas reservoir
CO_2	Flue gas
N_2	Air, nitrogen gas reservoirs as in the UAE

The main gas injection development schemes are gas cap gas injection, pattern gas injection including 5 spot, 7-spot, 9-spot, direct line drive and staggered line drive. Recently a down-flank peripheral gas injection has been piloted in Abu Dhabi.

Most of the producing reservoirs in Abu Dhabi have been considered for enhanced oil recovery by gas injection where either full schemes or gas injection pilots have been implemented.

Accurate design of the miscible gas injection projects with special attention to the level of the gas injection pressure, gas composition and the main variable of the reservoir characterization model is a necessary condition for the success of a gas injection process.

After all field tests, laboratory tests and studies, pilot tests are normally implemented to confirm future reservoir performance and minimize the risk before implementing the full field development scheme.

Detailed phase behavior studies should be conducted to define phase behavior envelops and to investigate asphaltene deposits and sulphur element deposit since these could affect the design of the development scheme including the operating conditions as well as subsurface and surface equipments.

The main disadvantages of miscible gas flooding are the high mobility ratio leading to viscous fingering and law sweep efficiency. Miscible WAG process could be used to minimize these demerits and thus improve the sweep efficiency. This process is assumed to have both advantages of water flooding and miscible gas flooding processes.

The sequence of fluid injection could affect the ultimate recovery of the WAG process. Starting with water injection in a water wet system could decrease the ultimate recovery due to shielding effect where water will decrease the contact of the gas with the oil leading to a decrease in the displacement efficiency.

It appears that two main variables should be critically considered when designing a WAG process. These are the first processes to start the WAG and the size of alternating gas and water slugs.

Combined water and gas injection process, SWAG, is different from WAG process where water and gas are injected simultaneously and selectively in a dual completed well. This process is not common worldwide. Again the main objective is to improve the areal and vertical sweep efficiencies in addition to a good displacement efficiency for a miscible gas process. This process is being tested in Abu Dhabi fields where it may be fully applied based on the filed test results.

5.3 Reservoir management

The production-injection profile is a strong multivariable function that controls the ultimate recovery factor. It is normally identified taking into account a strategy and a local economical model selected by management. Accordingly, the following rate options could be adopted and / or applied:

- The production profile shows a maximum rate initially and this rate declines practically without plateau.
- The production profile starts with plateau rate that will be maintained during plateau period and declines during drawdown production period.
- The production profile starts with a buildup rate during a buildup period, and continues to produce at a plateau rate during buildup period and finally with a drawdown rate during a drawdown period.

A long term strategy normally adopts production-injection profiles with buildup, plateau and drawdown rates and periods. A short term strategy on the other hand adopts production-injection profiles with only drawdown rate period where there are no buildup and plateau rate periods.

5.4 Long-term business plan

Normally the full field development plans optimized and selected, are multiphase. Each phase will be planned for implementation at the planned date. The long term business plan will therefore define the following:

- Project implementation plan of different phases.
- Capital and operating costs of the economical model.
- Production-injection plan as defined by the reservoir management.

It is to be noted that all these functions and variables defined by the business plan will be considered when preparing the production schedules and in case of conducting techno-economical studies.

5.5 Development Options Identification

To assess and select the development option that will maximize the ultimate recovery viable development options with the objective development process will be identified. All dependent variables that will affect the results of the study will be considered when defining the constraints.

In the study, the main objective is to select the development option that will maximize ultimate recovery factor for the EOR development processes of the NHGI comprising H_2S, CO_2 and N_2.

Based on the guidelines, the following main development options can be identified for the assessment study:

- EOR miscible / immiscible gas injection processes for the NHG N_2, CO_2 and H_2S.
- EOR miscible / immiscible gas injection processes for C_1, lean gas and rich gas. These cases will be treated as reference cases.

- For each EOR process, the following development options will be identified for assessment:
    - Gas continuous injection
    - Gas WAG / GAW
    - Gas combined with water, SWAG.

The following other development options were investigated but were not considered for technical assessment:

- Gas slug injection
- Gas mixture

Table 5.5-A presents the development options identified for further study and assessment.

Table 5.5-A: Development options identification

DEVELOPMENT OPTION IDENTIFICATION						
	DEVLOPMENT SCHEME		DEVELOPMENT PROCESS		RESERVOIR MANAGEMENT	
DEVELOPMENT OPTION	**Pattern**	**Spacing (ft)**	**Group**	**Injectant**	**Production Rate (STB/D)**	**Injection (MBBLS/D or MMSCF/D)**
H_2O	Direct line drive	2460	UPPER	-	-	-
			LOWER	H_2O	4000	8
			FIELD	H_2O	4000	8
H_2S	Direct line drive	2460	UPPER	-	-	-
			LOWER	H_2S	4000	12.5
			FIELD	H_2S	4000	12.5
H_2S-H_2O	Direct line drive	2460	UPPER	H_2O	-	4
			LOWER	H_2S	4000	12.5
			FIELD	H_2O +H_2S	4000	4 + 12.5
H_2S-WAG	Direct line drive	2460	UPPER	-	-	-
			LOWER	H_2S H_2O	4000	25, 8
			LOWER	H_2O H2S	-	8, 25
			FIELD	H_2O H2S	4000	8, 25

CO_2	Direct line drive	2460	UPPER	-	-	-
			LOWER	CO_2	4000	12.5
			FIELD	CO_2	4000	12.5
CO_2-H_2O	Direct line drive	2460	UPPER	CO_2	-	4
			LOWER	CO_2	4000	12.5
			FIELD	H_2O+CO2	4000	4 + 12.5
CO_2-WAG	Direct line drive	2460	UPPER	-	-	-
			LOWER	CO_2 H_2O	4000	25, 8
			LOWER	H_2O CO_2	-	8, 25
			FIELD	H_2O CO_2	4000	8, 25

N_2	Direct line drive	2460	UPPER	-	-	-
			LOWER	N_2	4000	12.5
			FIELD	N_2	4000	12.5
N_2-H_2O	Direct line drive	2460	UPPER	N_2	-	4
			LOWER	N_2	4000	12.5
			FIELD	H_2O+N2	4000	4 + 12.5
N_2-WAG	Direct line drive	2460	UPPER	-	-	-
			LOWER	N_2 H_2O	4000	25, 8
			LOWER	H_2O N_2	-	8, 25
			FIELD	H_2O N_2	4000	8, 25

AG/RG	Direct line drive	2460	UPPER	-	-	-
			LOWER	AG/RG	4000	12.5
			FIELD	AG/RG	4000	12.5
AG/RG - H_2O	Direct line drive	2460	UPPER	AG/RG	-	4
			LOWER	AG/RG	4000	12.5
			FIELD	H_2O+ AG/RG	4000	4 + 12.5
AG/RG - WAG	Direct line drive	2460	UPPER	-	-	-
			LOWER	AG/RG H_2O	4000	25, 8
			LOWER	H_2O AG/RG	-	8, 25
			FIELD	H_2O AG/RG	4000	8, 25

CHAPTER VI

DEVELOPMENT OPTIONS ASSESS STUDY

CHAPTER VI

DEVELOPMENT OPTIONS ASSESS STUDY

Three NHGI processes were defined and for each case, three development options were therefore identified for a development scheme.

The main NHGI processes are Nitrogen gas injection, Carbon Dioxide gas injection and Hydrogen Sulfide gas injection.

The main development options are continuous gas injection, WAG injection, combined gas, and water injection.

6.1 H_2S-EOR Development Process

Mainly the following prediction runs were simulated:

- H_2S gas continuous injection
- H_2S gas combined with water
- H_2S gas WAG

6.1.1 H_2S gas continuous injection

The prediction run H_2S gas continuous injection is defined by Table 6.1.1-A. The results are shown in Figure 6.1.1-A and Table 6.1.1-B. The main results can be summarized as follows:

- The plateau period was 34 years.
- Oil producers were closed because the GOR exceeds the maximum GOR of 10 MSCF/STB.
- The gas breakthrough took place after 9 years.
- The reservoir pressure increased before gas breakthrough and reach a maximum value of about 5800 psig and started to decrease after gas breakthrough where it reached a minimum value of about 2800 psig.
- The plateau rate could be extended if the gas injection rate was increased and the GOR constraint was relaxed to more than 10 MSCF/STB.

Table 6.1.1-A: H_2S gas continuous injection development option

Development Scheme		
Area	Middip	
Well Pattern	Direct line drive	
Well Completion	Producers	Lateral
	Injectors	Lateral
Development Process		
Injectant	Upper	-
	Lower	Hydrogen Sulphide
Reservoir Management		
Water Injection	Upper	-
	Lower	-
Oil Production	Upper	0.0 MSTBD
	Lower	4.0 MSTBD
Gas Injection	Upper	0.0 MMSCFD
	Lower	25 MMSCF/D
Business Plan		
Phases	One Phase	

Table 6.1.1:-B H_2S gas continuous injection results

Development Option Results								
Development Option	Field Plateau Production Rate (STB/D)	Field Plateau Gas injection Rate (MMSCF/D)	Field Plateau Water injection Rate (BBLS/D)	Plateau Period (Years)	FOPT (MMSTB)	FGPT (MMSCF)	FWPT (BBLS)	URF (%)
H_2S	4000	25	0	34	5.0E+7	2.1E+8	0	56.5

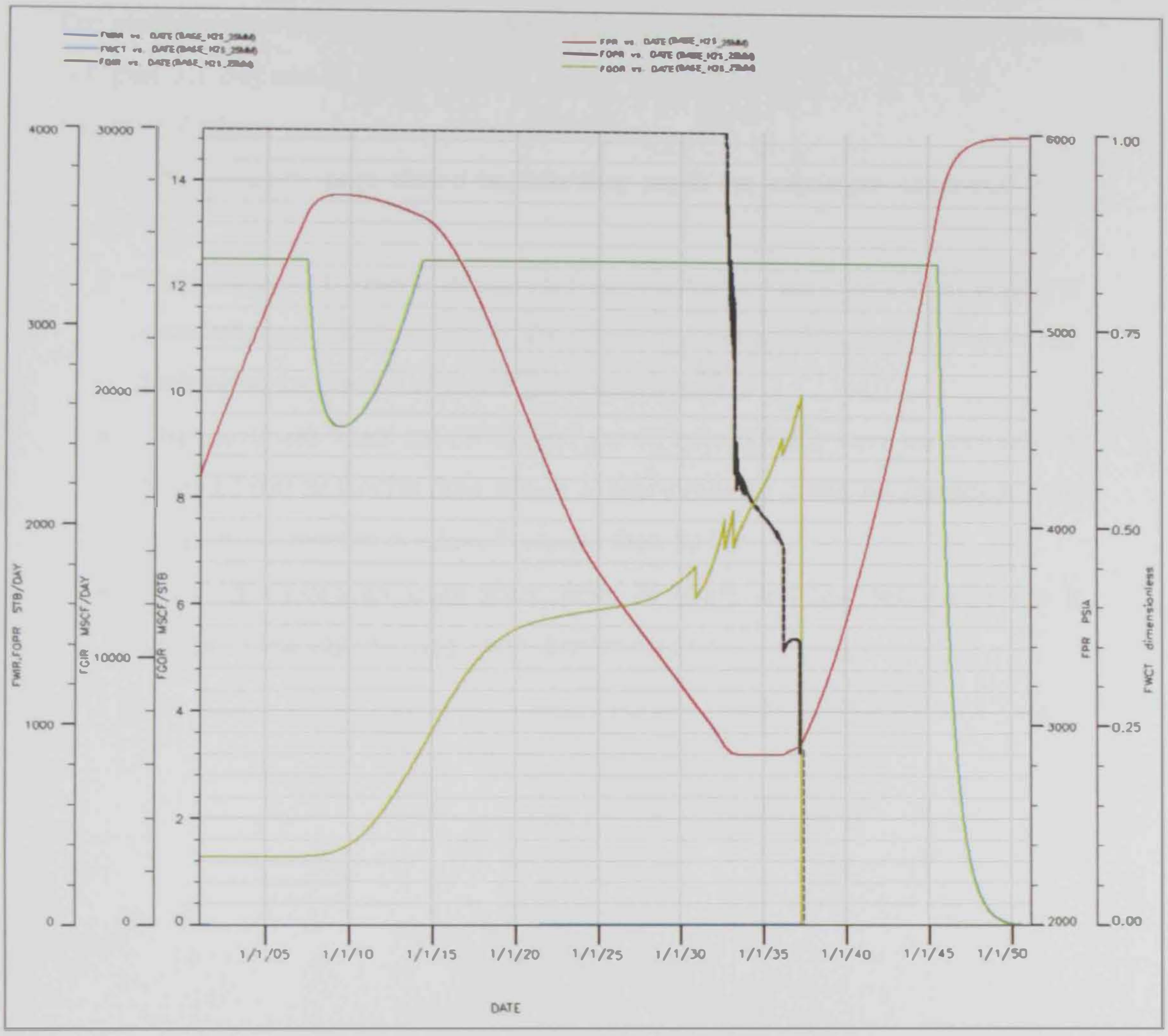

Figure 6.1.1-A: H_2S gas continuous injection reservoir performance

6.1.2 H_2S gas injection combined with water

The prediction run H_2S- H_2O-CO is defined by Table 6.1.2-A. The results are shown in Figure 6.1.2-A and by Table 6.1.2-B.

The main findings can be summarized as follows:

- Oil producers were closed because they reach the maximum water cut of 50 %.
- The plateaus of water injection rate was maintained only for a short period of time because of the increase of the reservoir pressure. The water injection rate built up to the plateau after the gas breakthrough.
- The maximum water cut (WC), and gas oil ratio (GOR), were respectively 50 % and 5800 SCF/STB. The life of a well producer could be extended if the water cut constraint is relaxed to more than 50 %.
- Water breakthrough takes place after 40 years and fast WC builds up is indicated leading to a very short drawdown period.

Table 6.1.2-A: H_2S gas injection combined with water development option

Development Scheme		
Area	Middip	
Well Pattern	Direct line drive	
Well Completion	Producers	Lateral
	Injectors	Lateral
Development Process		
Injectant	Upper	-
	Lower	Hydrogen Sulphide, Water
Reservoir Management		
Water Injection	Upper	-
	Lower	4.0 MSTBD
Oil Production	Upper	0.0 MSTBD
	Lower	4.0 MSTBD
Gas Injection	Upper	0.0 MMSCFD
	Lower	12.5 MMSCF/D
Business Plan		
Phases	One Phase	

Table 6.1.2-B: H_2S gas injection combined with water results

Development Option Results								
Development Option	**Field Plateau Production Rate (STB/D)**	**Field Plateau Gas injection Rate (MMSCF/D)**	**Field Plateau Water injection Rate (BBLS/D)**	**Plateau Period (Years)**	**FOPT (STB)**	**FGPT (MSCF)**	**FWPT (BBLS)**	**URF (%)**
H_2S, WATER	4000	12.5	4000	39	5.8E+7	1.68E+8	0.15E+7	65.6

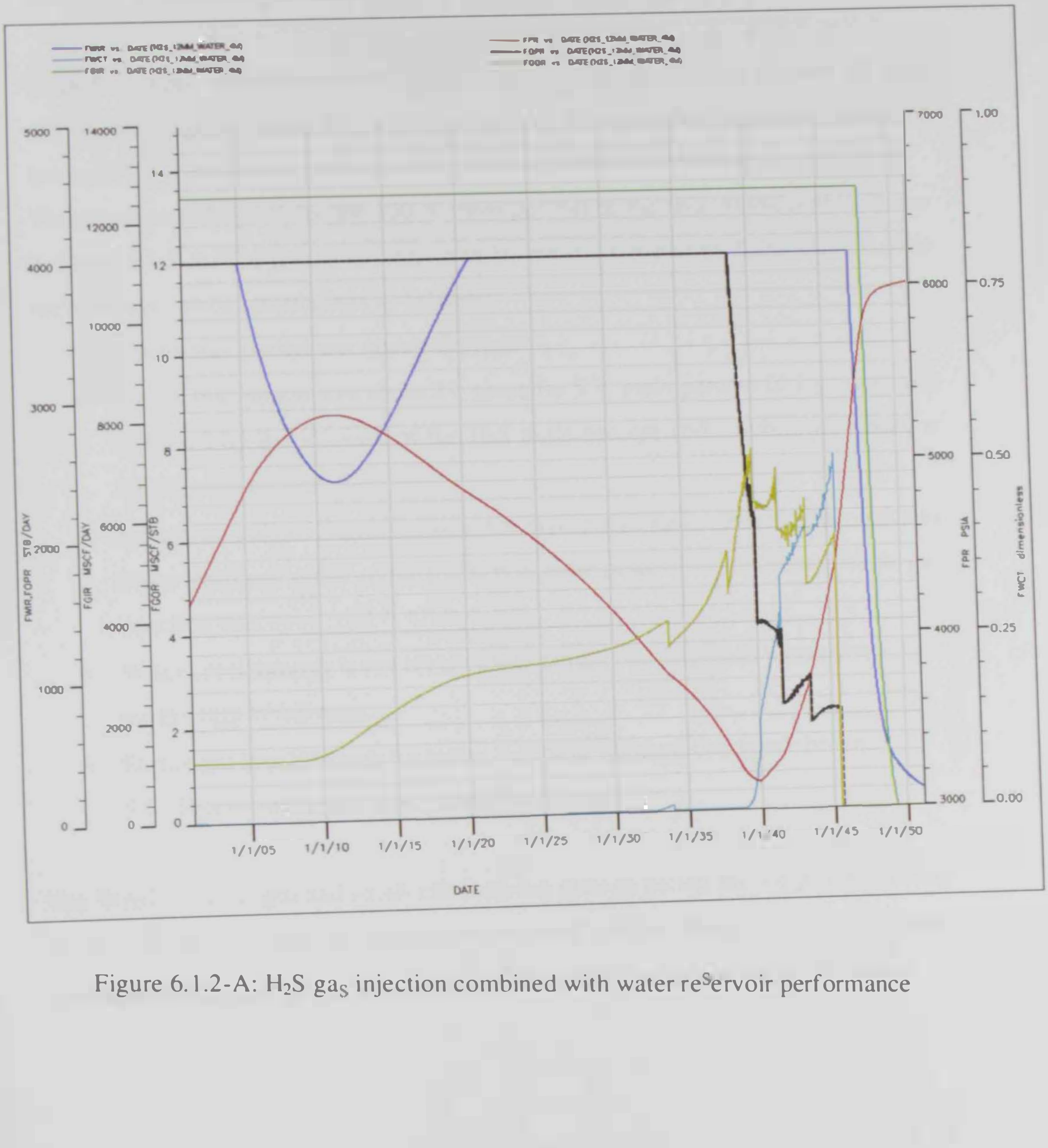

Figure 6.1.2-A: H_2S gas injection combined with water reservoir performance

6.1.3 H_2S –WAG injection

Prediction runs H_2S-Mixture-WAG were conducted where more percent of H_2S component ranges between 5% - 100 %. However, the reservoir framework results are not reported

The development option for the 100 % mole percent of the H_2S component is shown in Table 6.1.3-A. The results are shown in Figure 6.1.3-A and by Table 6.1.3-B. The main results can be summarized as follows:

- The plateau period was about 42 years.
- The plateau period was about 27 years for 5 % mole percent H_2S process and increased by the increase of the H_2S mole percent and reached 42 years for 100 % mole percent H_2S.
- Formation volume factor is lower for higher H_2S mole percent. This leads to higher reservoir pressure for lower H_2S mole percent for the same plateau gas injection rate.
- Water breakthrough is not taking place during that indicated prediction period for the H_2S-WAG case.
- Earlier gas breakthrough for lower H_2S mole percent. Gas breakthrough of 5 % H_2S mole percent took place after 6 years.

The WAG cycle length had small effect on the plateau period for the process having 50 % mole percent H_2S. It is apparent however shorter WAG cycle gives longer plateau period.

Table 6.1.3-A: H_2S-WAG development option

Development Scheme		
Area	Middip	
Well Pattern	Direct line drive	
Well Completion	Producers	Lateral
	Injectors	Lateral
Development Process		
Injectant	Upper	-
	Lower	Water,Hydrogen Sulphide
Reservoir Management		
Water Injection	Upper	-
	Lower	8.0 MSTBD
Oil Production	Upper	0.0 MSTBD
	Lower	4.0 MSTBD
Gas Injection	Upper	0.0 MMSCFD
	Lower	25 MMSCF/D
Business Plan		
Phases	One Phase	

Table 6.1.3-B: H_2S-WAG results

Development Option Results								
Development Option	**Field Plateau Production Rate (STB/D)**	**Field Plateau Gas injection Rate (MMSCF/D)**	**Field Plateau Water injection Rate (BBLS/D)**	**Plateau Period (Years)**	**FOPT (STB)**	**FGPT (MSCF)**	**FWPT (BBLS)**	**URF (%)**
H_2S WAG	4000	25	8000	42	6.2E+7	1.65E+8	0	70.1

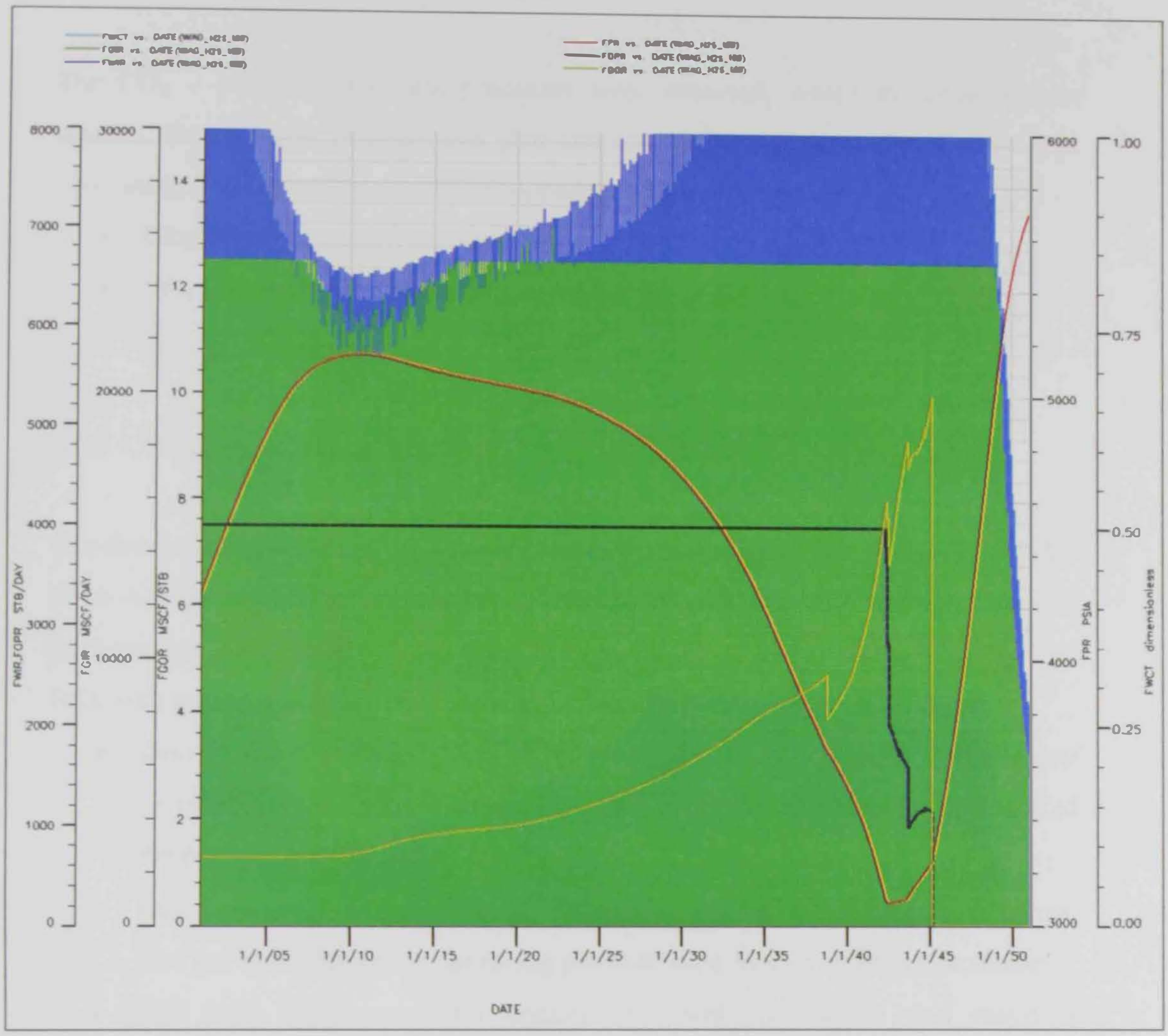

Figure 6.1.3-A: H_2S-WAG reservoir performance

6.2 CO_2– EOR development process

The CO_2 – EOR development processes were assessed, where the development scheme, the reservoir management plan and optimizing plans constrains were kept equivalent. The following are the development options studied.

- CO_2 gas continuous injection
- CO_2 gas and water injection co current / combined
- CO_2 gas WAG injection

6.2.1 CO_2 gas continuous injection

The development option of the development process was identified as shown in Table 6.2.1-A. The prediction run was conducted to predict the well and the reservoir performance. The results are presented in Figure 6.2.1-A and by Table 6.2.1-B . The following main findings can be drawn and presented.

- Gravity segregation is taking places where gas flows vertically to the higher permeability layers and horizontally in the upper layers and again vertically to the producing holes in the lower part.
- Gas fingering and channeling are taking place in lateral heterogeneous layers. The gas breakthrough is not taking place at same time in different producers.
- The high GOR constraint controls the well production and reservoir production performance.
- Relatively, the gas breakthrough was taking place fast where the flow dominates vertically in the neighborhood of the injectors, laterally in the upper higher permeability layers and finally vertically in the neighbor hood of the producers.
- Cycling higher gas injection rate after gas breakthrough will be inevitable in order to maintain the reservoir pressure. A balanced production – injection scheme could be identified and applied.

Table 6.2.1-A: CO_2 gas continuous injection development option

Development Scheme		
Area	Middip	
Well Pattern	Direct line drive	
Well Completion	Producers	Lateral
	Injectors	Lateral
Development Process		
Injectant	Upper	-
	Lower	Carbon Dioxide
Reservoir Management		
Water Injection	Upper	-
	Lower	-
Oil Production	Upper	0.0 MSTBD
	Lower	4.0 MSTBD
Gas Injection	Upper	0.0 MMSCFD
	Lower	25 MMSCF/D
Business Plan		
Phases	One Phase	

Table 6.2.1-B: CO_2 gas continuous injection results

Development Option Results								
Development Option	Field Plateau Production Rate (STB/D)	Field Plateau Gas injection Rate (MMSCF/D)	Field Plateau Water injection Rate (BBLS/D)	Plateau Period (Years)	FOPT (STB)	FGPT (MSCF)	FWPT (BBLS)	URF (%)
CO_2	4000	25	0	26	4.9E+7	2E+8	0	55.4

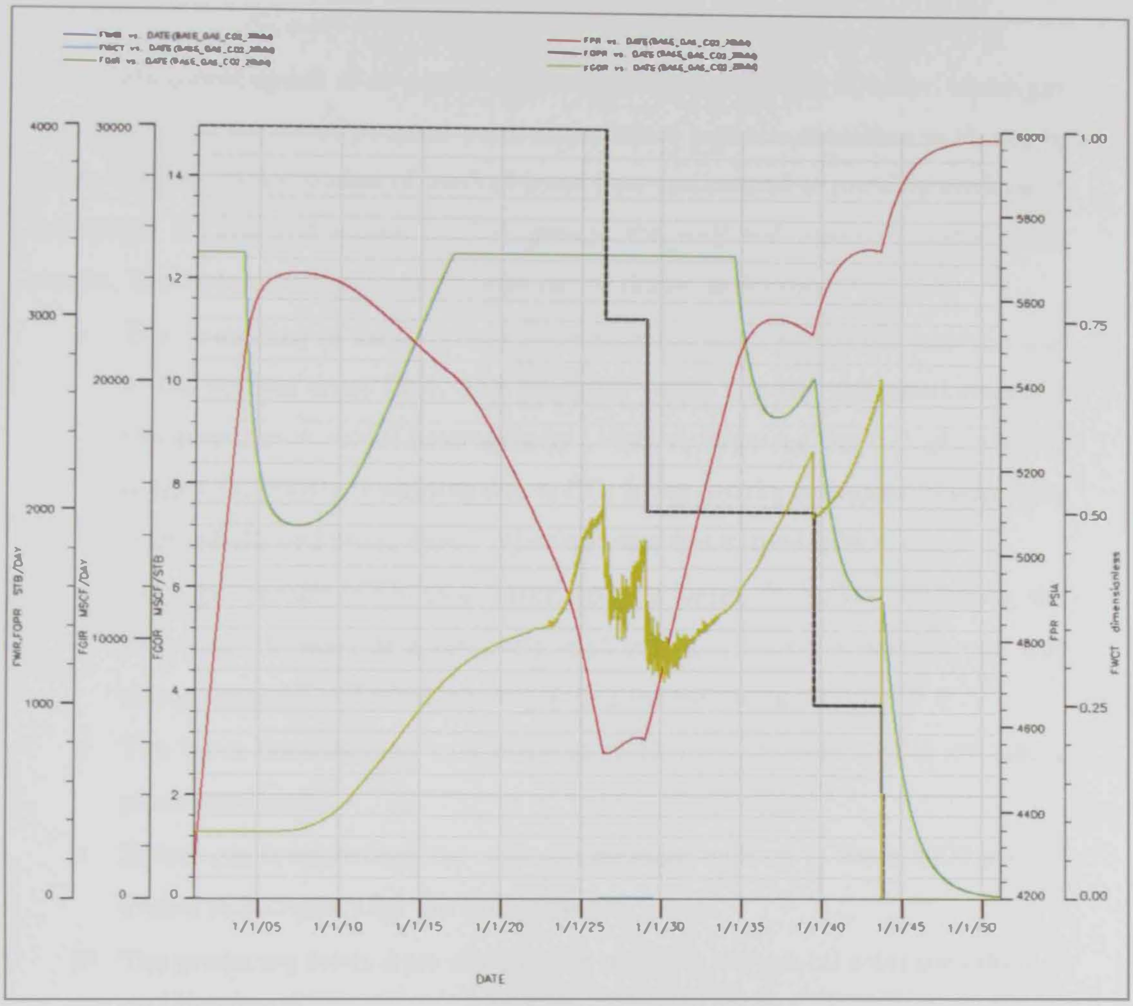

Figure 6.2.1-A: CO_2 gas continuous injection reservoir performance

6.2.2 CO_2 gas and water injection co-current / combined

The development option of co-current CO_2 miscible gas and water injection where gas was injected in the lower part and water in the lower part was identified as shown in Table 6.2.2-A. Minimization of vertical cross flow and control of mobility are looked for. Table 6.2.2-B and Figure 6.2.2-A present the well and reservoir performance results. The main results and conclusions can be drawn as follows:

- The channeling of the CO_2 bank is noted in the upper part of the reservoir due to the vertical cross flow. The dominant cause was the integrated reservoir characterization model heterogeneity , viscous fingering due to high mobility of the CO_2 gravity overriding due to CO_2 lower density compared to water and high imbalanced production – injection rates that exceed critical rates.
- CO_2 gas breakthrough took place after 9 years. It builds up during the following 10 years at a relatively high rate and then the buildup rate was almost constant and relatively low during the following 10 years.
- The water breakthrough took place after 42 years. However, it is not taking place dominantly.
- Before gas breakthrough the reservoir pressure built up to about 5800 psi and started to decrease after gas breakthrough.
- The producing wells were closed after reaching the gas oil ratio constraint of 10 MSCF/STB.

Table 6.2.2- A: CO_2 Gas and water injection co-current / combined development option

Development Scheme		
Area	Middip	
Well Pattern	Direct line drive	
Well Completion	Producers	Lateral
	Injectors	Lateral
Development Process		
Injectant	Upper	-
	Lower	Carbon Dioxide, Water
Reservoir Management		
Water Injection	Upper	-
	Lower	4.0 MSTBD
Oil Production	Upper	0.0 MSTBD
	Lower	4.0 MSTBD
Gas Injection	Upper	0.0 MMSCFD
	Lower	12.5 MMSCF/D
Business Plan		
Phases	One Phase	

Table 6.2.2- B: CO_2 Gas and water injection co-current / combined results

Development Option Results								
Development Option	Field Plateau Production Rate (STB/D)	Field Plateau Gas injection Rate (MMSCF/D)	Field Plateau Water injection Rate (BBLS/D)	Plateau Period (Years)	FOPT (STB)	FGPT (MSCF)	FWPT (BBLS)	URF (%)
CO_2, WATER	4000	12.5	4000	34	5.7E+7	1.7E+8	0.03E+7	64.5

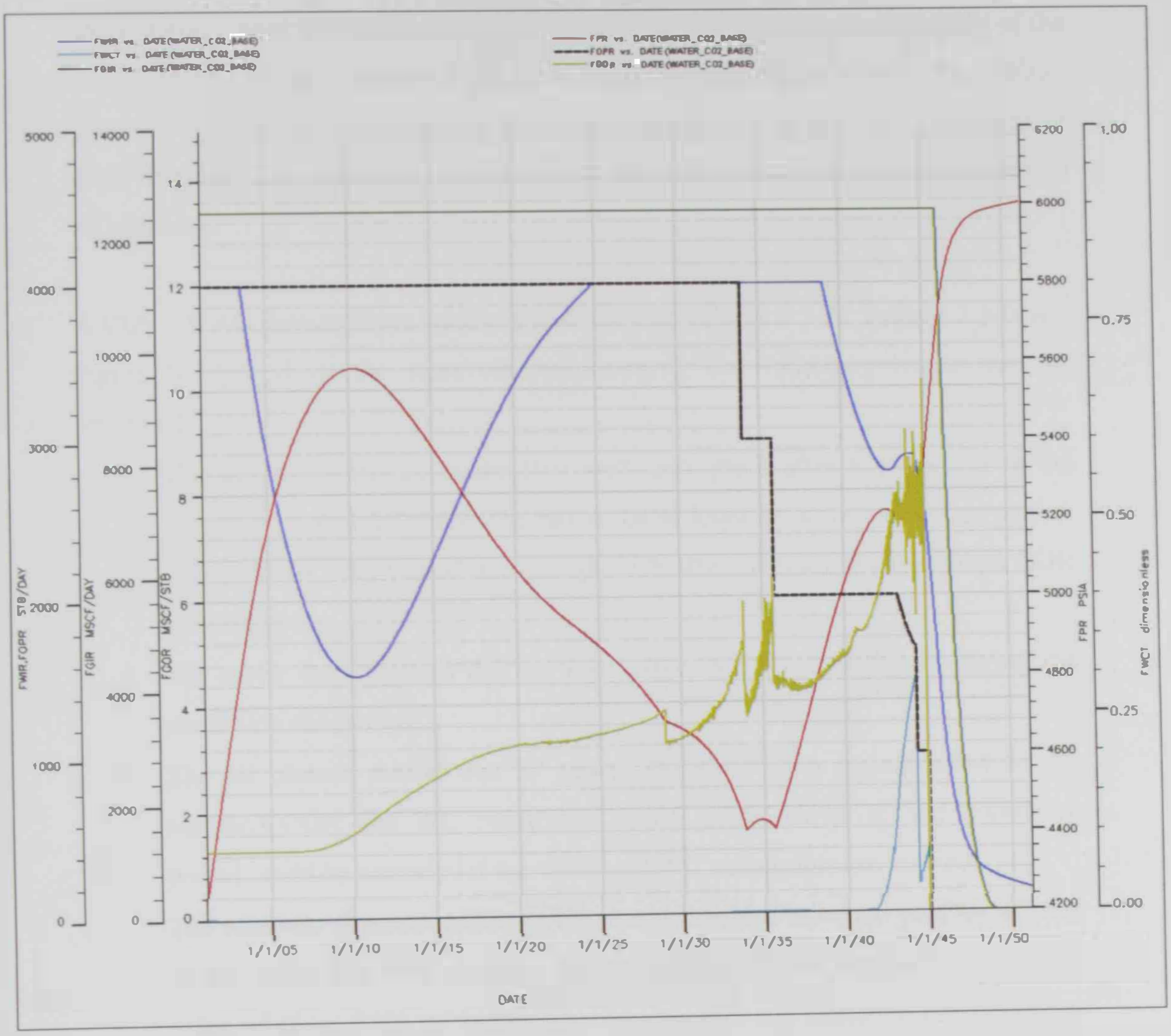

Figure 6.2.2-A: CO_2 Gas and water injection co-current / combined

Reservoir performance

6.2.3 CO_2-WAG injection

Oil swelling, mass transfer and increase in mobility and then the displacement of the new fluid by CO_2 gas / water are the main recovery mechanisms of the CO_2 – WAG process. In a layered reservoir, the WAG process appears to have the advantage of achieving the WAG process in all layers and possibly better areal and vertical sweep efficiencies.

A CO_2 – WAG development option is described in Table 6.2.3-A. Table 6.2.3-B and Figure 6.2.3-A show the reservoir performance. The following results can be presented:

- The gas breakthrough in the first well took place after 9 years and in the second well after 20 years. The rate of GOR increase is clear after this period. All the wells were closed due to high GOR that exceeded the maximum GOR after 45 years.
- The water breakthrough did not take place in the oil producers during the prediction run period.
- The oil plateau period was 37 years. The drawdown period based on the assumed GOR and WC constraints was 9 years. However, the drawdown period could be extended if the GOR and WC constraints are relaxed.
- The reservoir pressure followed the production and injection profiles as well as the GOR and WC profiles. The reservoir pressure reached a maximum value of about 5500 psi before gas breakthrough and started to decrease after gas breakthrough where it reached a minimum value of about 4700 psi at the end of the plateau period when it started to build up again during the drawdown period.

Table 6.2.3- A: CO_2-WAG injection development option

Development Scheme		
Area	Middip	
Well Pattern	Direct line drive	
Well Completion	Producers	Lateral
	Injectors	Lateral
Development Process		
Injectant	Upper	
	Lower	Water, Hydrogen Sulphide
Reservoir Management		
Water Injection	Upper	-
	Lower	8.0 MSTBD
Oil Production	Upper	0.0 MSTBD
	Lower	4.0 MSTBD
Gas Injection	Upper	0.0 MMSCFD
	Lower	25 MMSCF/D
Business Plan		
Phases	One Phase	

Table 6.2.3- B: CO_2-WAG injection results

Development Option Results								
Development Option	Field Plateau Production Rate (STB/D)	Field Plateau Gas injection Rate (MMSCF/D)	Field Plateau Water injection Rate (BBLS/D)	Plateau Period (Years)	FOPT (STB)	FGPT (MSCF)	FWPT (BBLS)	URF (%)
CO_2 WAG	4000	25	8	37	5.7E+7	1.54E+8	0.01E+7	64.5

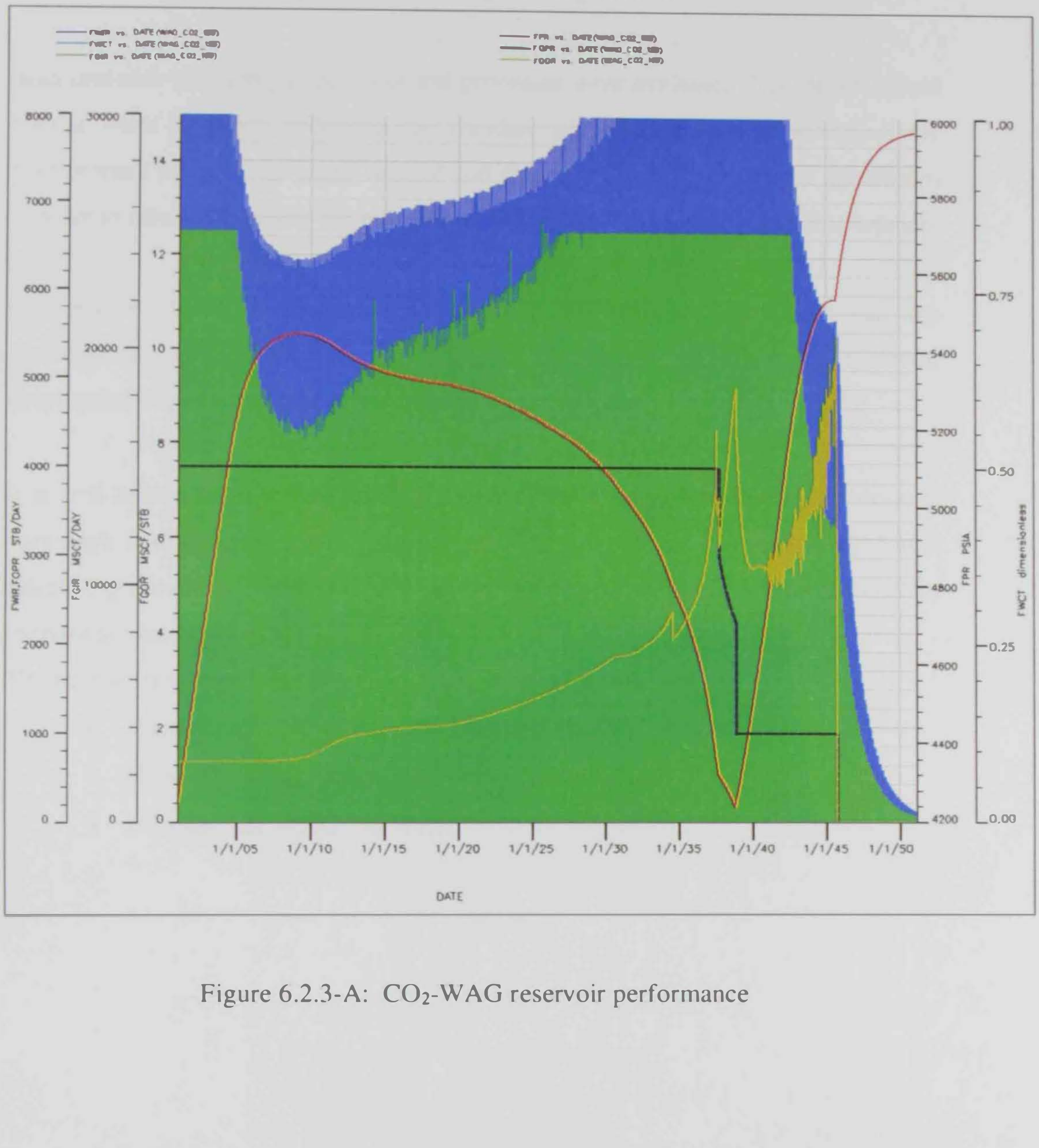

Figure 6.2.3-A: CO_2-WAG reservoir performance

6.3 Nitrogen gas injection development process

High pressure nitrogen gas development processes were evaluated. The development options were identified following the standard procedure presented where all the development variables of areal, vertical and displacement efficiencies are considered in order to maximize finally the ultimate recovery factor for nitrogen gas development processes.

Furthermore, these development options will be optimized together with the development options of other processes to optimize / maximize the reservoir development option that will give optimum recovery factor.

It is well known that the miscibility pressure of the nitrogen gas injection process is very high and in many cases it is not practical to achieve the miscibility / near miscibility conditions. However, it is always interesting to confirm these factors for individual cases studied.

The following nitrogen gas processes were assessed as follows:

- Nitrogen gas, N_2, continuous injection, N_2-C
- Nitrogen gas and co-current water injection, N_2-H_2O-CO
- Nitrogen gas WAG, N_2-WAG

6.3.1 Nitrogen gas continuous injection

Table 6.3.1-A shows a summary of the development option for this process including development scheme, reservoir management plan defining the production – injection plan, the business and operating plans where all project phases will be implemented initially for this study.

Table 6.3.1-B shows a summary for the reservoir performance derived from the well performances. Figure 6.3.1-A shows the reservoir performance including oil, gas and water production and injection profiles, pressure profile, water cut and GOR profiles. Based on these results the following conclusions could be summarized:

- Unfavorable macroscopic (areal and vertical) and microscopic displacement sweep efficiencies leading to relatively low ultimate recovery factor and a short plateau period of 17 years.
- Combined with relatively short plateau period, a short 3 years drawdown period was achieved. The producers were closed due to high GOR where the reservoir GOR reached 10 MSCF/STB at the end of the drawdown period.
- In view of the high mobility, the reservoir pressure built up very quickly to about 5800 psi from the initial pressure of 4175 psi. As it is known, the mobility ratio should be less than one in order to have favorable mobility ratio.
- The viscous to gravity forces ratio looks unfavorable and this leads to high cross flow in the neighborhood of injectors and high lateral velocity in the upper part and an opposite cross flow in the neighbor hood of producers leading to early gas breakthrough after 5 years.
- The short drawdown period could be extended but shortly if the GOR constraint is relaxed where the GOR could be more than 10 MSCF/STB.

Table 6.3.1-A: Nitrogen gas continuous injection process development option

Development Scheme		
Area	Middip	
Well Pattern	Direct line drive	
Well Completion	Producers	Lateral
	Injectors	Lateral
Development Process		
Injectant	Upper	-
	Lower	Nitrogen
Reservoir Management		
Water Injection	Upper	-
	Lower	-
Oil Production	Upper	0.0 MSTBD
	Lower	4.0 MSTBD
Gas Injection	Upper	0.0 MMSCFD
	Lower	25 MMSCF/D
Business Plan		
Phases	One Phase	

Table 6.3.1-B: Nitrogen gas continuous injection process results

Development Option Results								
Development Option	**Field Plateau Production Rate (STB/D)**	**Field Plateau Gas injection Rate (MMSCF/D)**	**Field Plateau Water injection Rate (BBLS/D)**	**Plateau Period (Years)**	**FOPT (STB)**	**FGPT (MSCF)**	**FWPT (BBLS)**	**URF (%)**
N_2	4000	25	0	17	2.4E+7	4.9E+7	0	27.1

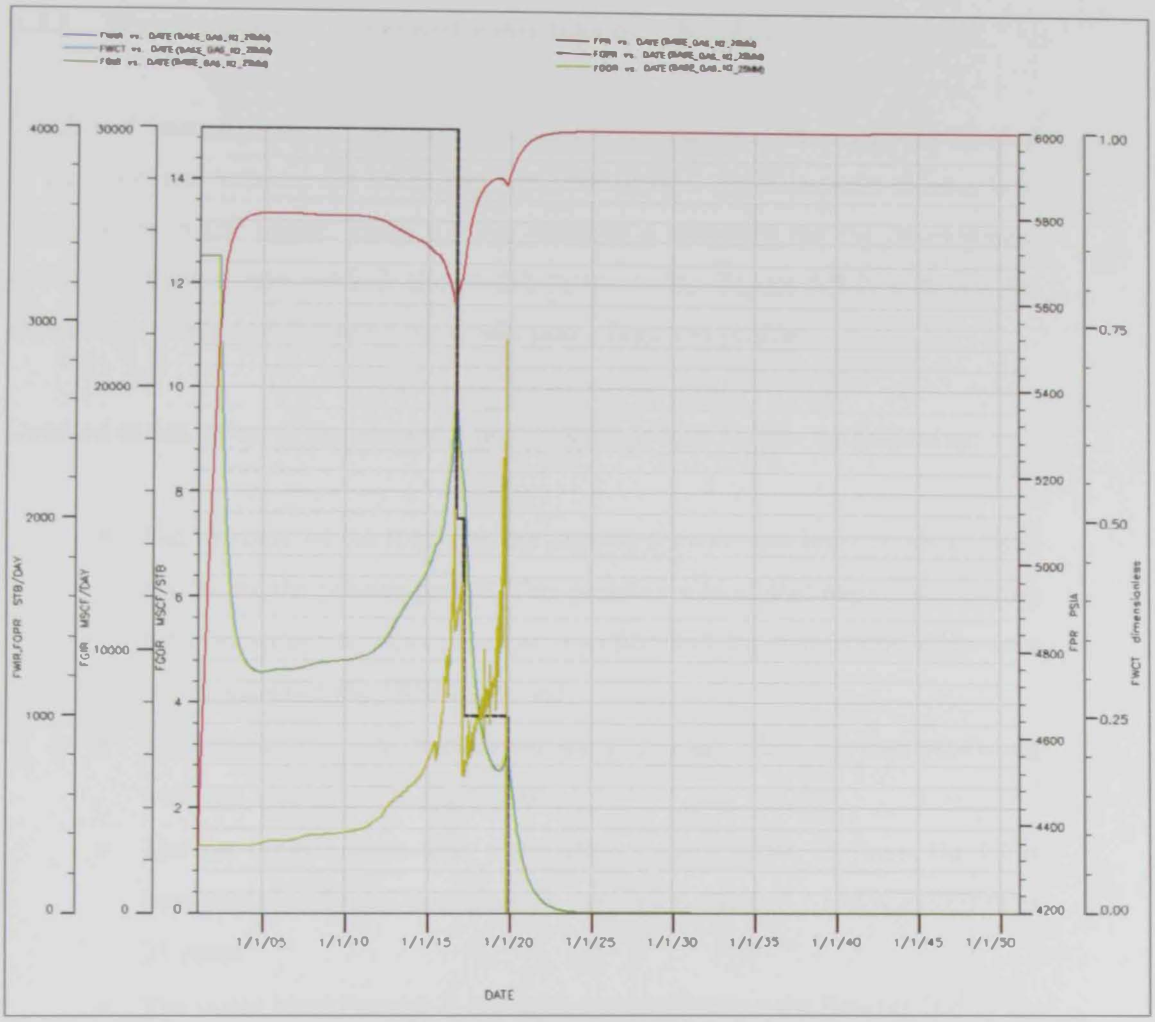

Figure 6.3.1-A: N_2 gas continuous injection reservoir performance

6.3.2 Nitrogen gas and co-current water injection (N_2-H_2O-CO)

Combined / simultaneous N_2 gas and water injection process , where gas was injected in the lower and water in the lower part was investigated. An alternative scheme is to inject water in the upper. Table 6.3.2-A presents a summary for the development options studied. Table 6.3.2-B shows the main results. Figure 6.3.2-A shows the reservoir performance including the production – injection profiles.

Detailed examination of the presented performance results reveals the following:

- fast increase of the reservoir pressure to a maximum level of about 5850 psi during the plateau period. This pressure was almost maintained during the plateau period where the gas injection and water injection rates were increased when the GOR increased.
- The plateau rate was maintained for 17.5 years when the first producing well was closed due to high GOR.
- The gas breakthrough took place after 5 years. After 15 years, the GOR increased steeply and exceeded the maximum GOR of 10 MSCF/STB after 23 years.
- The water breakthrough is not taking place because the flowing life of the producers is relatively short.
- The drawdown period was 10 years where the producers were closed due to GOR being more than 10 MSCF/STB.

Table 6.3.2-A: Nitrogen gas and co-current water injection development option

Development Scheme		
Area	Middip	
Well Pattern	Direct line drive	
Well Completion	Producers	Lateral
	Injectors	Lateral
Development Process		
Injectant	Upper	-
	Lower	Nitrogen, Water
Reservoir Management		
Water Injection	Upper	-
	Lower	4.0 MSTBD
Oil Production	Upper	0.0 MSTBD
	Lower	4.0 MSTBD
Gas Injection	Upper	0.0 MMSCFD
	Lower	12.5 MMSCF/D
Business Plan		
Phases	One Phase	

Table 6.3.2-B: Nitrogen gas and co-current water injection results

Development Option Results								
Development Option	**Field Plateau Production Rate (STB/D)**	**Field Plateau Gas injection Rate (MMSCF/D)**	**Field Plateau Water injection Rate (BBLS/D)**	**Plateau Period (Years)**	**FOPT (STB)**	**FGPT (MSCF)**	**FWPT (BBLS)**	**URF (%)**
N2 , WATER	4000	12.5	4000	17.5	2.7E+7	5.4E+7	0	30.5

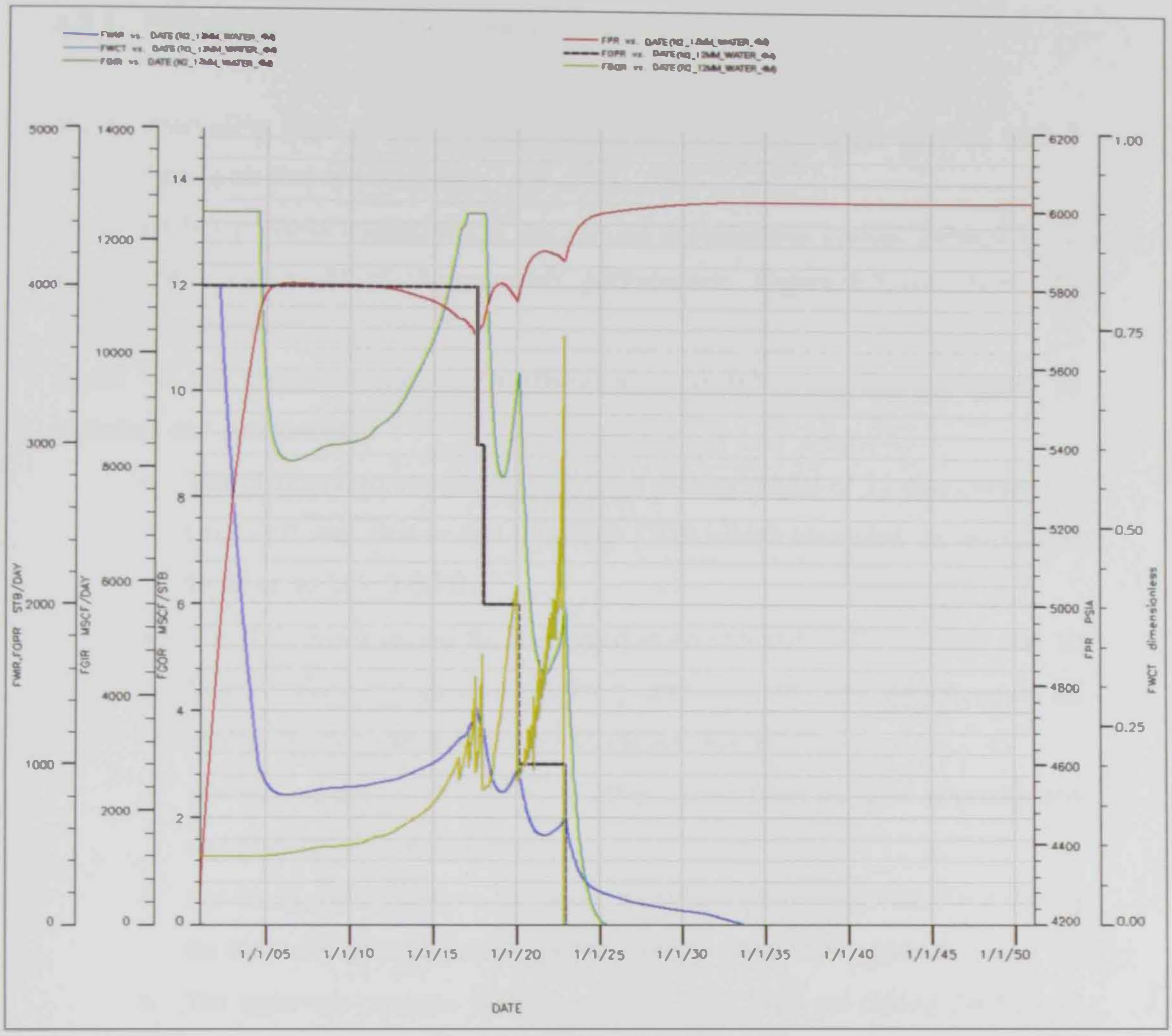

Figure 6.3.2-A: N_2 Gas and water injection co-current / combined Reservoir performance

6.3.3 Nitrogen Gas – WAG injection

Water alternating high pressure nitrogen gas, WAG, development process with 1 month time cycle was investigated.

Table 6.3.3-A presents a summary of the studied development option. Table 6.3.3-B shows the main results of the reservoir performance. Figure 6.3.3-A shows the reservoir performance.

Based on the presented reservoir performance, the following findings could be indicated and summarized.

- The plateau rate was maintained for a plateau period of 21 years when the first well was shut-in due to a high GOR which exceeded the maximum GOR of 10 MSCF/STB.
- The drawdown period for the stated water cut and GOR of 50 % and 10 MSCF/STB constraints respectively was 5 years. This period could be extended when the current constraints are relaxed.
- The gas breakthrough took place after 7 years from the start of production and performed as stated above.
- For the N_2-WAG option, the water breakthrough did not take place during the indicated plateau period nor the indicated drawdown period.
- The reservoir pressure built up to more than 5100 psi during the first 10 years of the plateau period. It dropped then to about 4600 psi at the end of the plateau period where the GOR was building up.
- The WAG time cycle has small effect on the performance of the studied reservoir and the time cycle studied ranges between 1 month and 1 year.

Table 6.3.3-A: Nitrogen Gas – WAG development options

Development Scheme		
Area	Middip	
Well Pattern	Direct line drive	
Well Completion	Producers	Lateral
	Injectors	Lateral
Development Process		
Injectant	Upper	-
	Lower	Water, Nitrogen
Reservoir Management		
Water Injection	Upper	-
	Lower	8.0 MSTBD
Oil Production	Upper	0.0 MSTBD
	Lower	4.0 MSTBD
Gas Injection	Upper	0.0 MMSCFD
	Lower	25 MMSCF/D
Business Plan		
Phases	One Phase	

Table 6.3.3-B: Nitrogen Gas – WAG development options

Development Option Results								
Development Option	Field Plateau Production Rate (STB/D)	Field Plateau Gas injection Rate (MMSCF/D)	Field Plateau Water injection Rate (BBLS/D)	Plateau Period (Years)	FOPT (STB)	FGPT (MSCF)	FWPT (BBLS)	URF (%)
N2 WAG	4000	25	8000	21	3E+7	6.6E+7	0	33.9

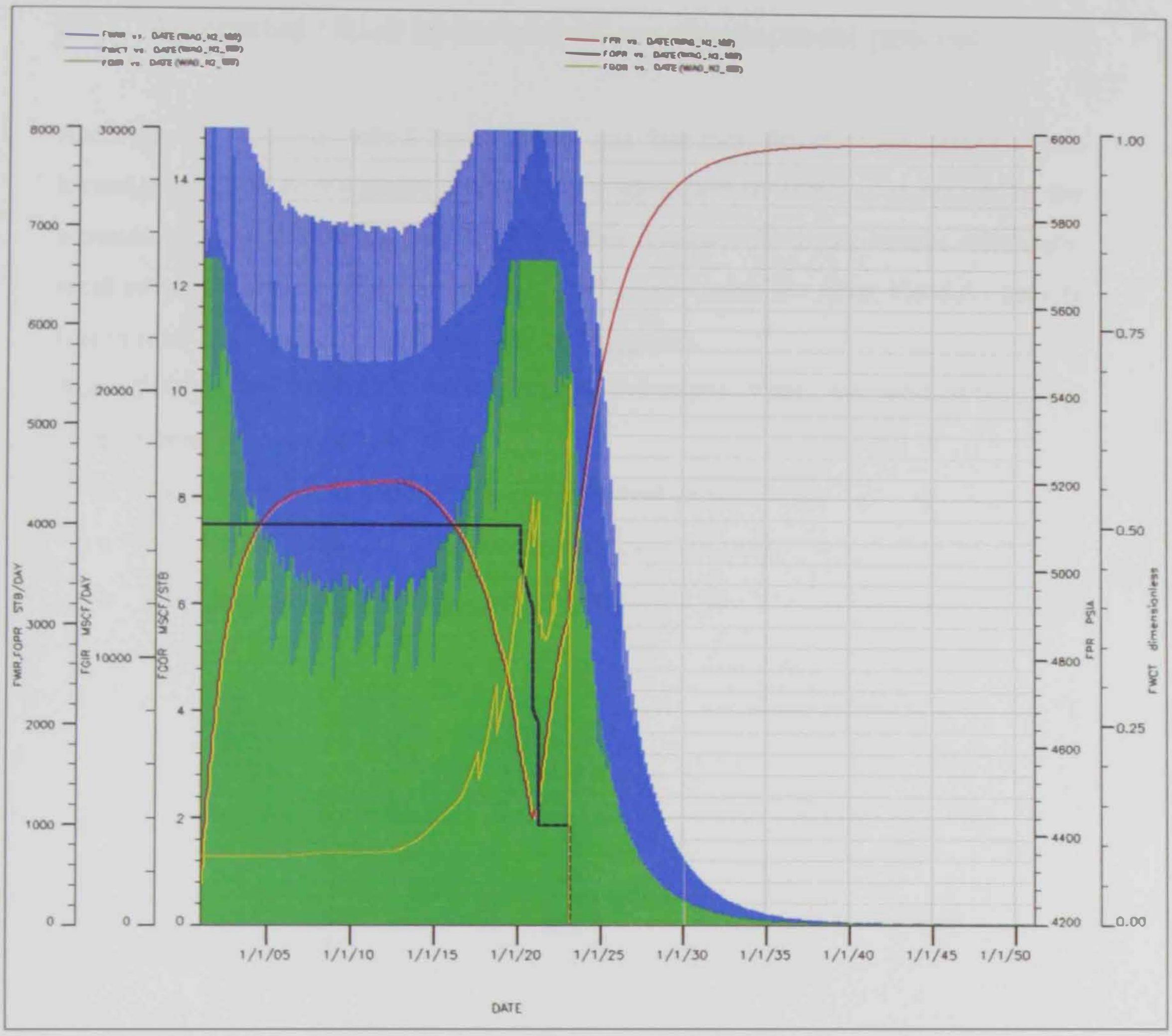

Figure 6.3.3-A: N_2-WAG reservoir performance

6.4 Associated / Rich hydrocarbon gas development process

Associated / rich / enriched hydrocarbon gas injection development process was investigated. The development options were identified to assess and maximize the ultimate recovery factor. In order to maximize microscopic displacement efficiency, areal sweep efficiency, and vertical sweep efficiency, mobility ratio, viscous / gravity forces ratio and capillary number would be favorable.

Accordingly, the following development processes were assessed where the development scheme was the same.

- AG / RG continuous injection development process.
- AG / RG – H_2O- CO injection development process.
- AG / RG – WAG development process.

6.4.1 AG/RG continuous injection development process

Table 6.4.1-A presents the development option assessed. Table 6.4.1-B shows a summary of the results of the reservoir performance.

Figure 6.4.1-A shows the reservoir performance profiles predicted. The interpretation of the pressure, production and injection performances indicated the following:

- Before gas breakthrough, the average gas formation volume factor was less than 1750 SCF/STB.
- The time of gas breakthrough was after 8 years from the start of prediction. The reservoir GOR continued to increase at a rate of about 300 SCF/STB/year for 15 years. It increased then steeply to reach 6 MSCF/STB at the end of the plateau period.
- All the wells achieved the maximum GOR constraint at the end of the drawdown period, where the whole life of the reservoir is 44 years.
- The maximum average reservoir pressure was about 5800 psi before gas breakthrough and started to decrease to reach 5000 psi at the end of the plateau period. Based on known laboratory data, this pressure is higher than the minimum miscibility pressure.
- The plateau rate was maintained for 32 years. The well GOR of a producer reached the maximum GOR of 10 MSCF/STB at this date. The plateau period could be extended by relaxing the well GOR constraint to more than 10 MSCF/STB.

Table 6.4.1-A: Associated/ Rich Gas continuous injection development option

Development Scheme		
Area	Middip	
Well Pattern	Direct line drive	
Well Completion	Producers	Lateral
	Injectors	Lateral
Development Process		
Injectant	Upper	-
	Lower	Associated/ Rich gas
Reservoir Management		
Water Injection	Upper	-
	Lower	-
Oil Production	Upper	0.0 MSTBD
	Lower	4.0 MSTBD
Gas Injection	Upper	0.0 MMSCFD
	Lower	25 MMSCF/D
Business Plan		
Phases	One Phase	

Table 6.4.1-B: Associated/ Rich Gas continuous injection results

Development Option Results								
Development Option	Field Plateau Production Rate (STB/D)	Field Plateau Gas injection Rate (MMSCF/D)	Field Plateau Water injection Rate (BBLS/D)	Plateau Period (Years)	FOPT (STB)	FGPT (MSCF)	FWPT (BBLS)	URF (%)
AG/ RG	4000	25	0	32	4.9E+7	1.36E+8	0	55.4

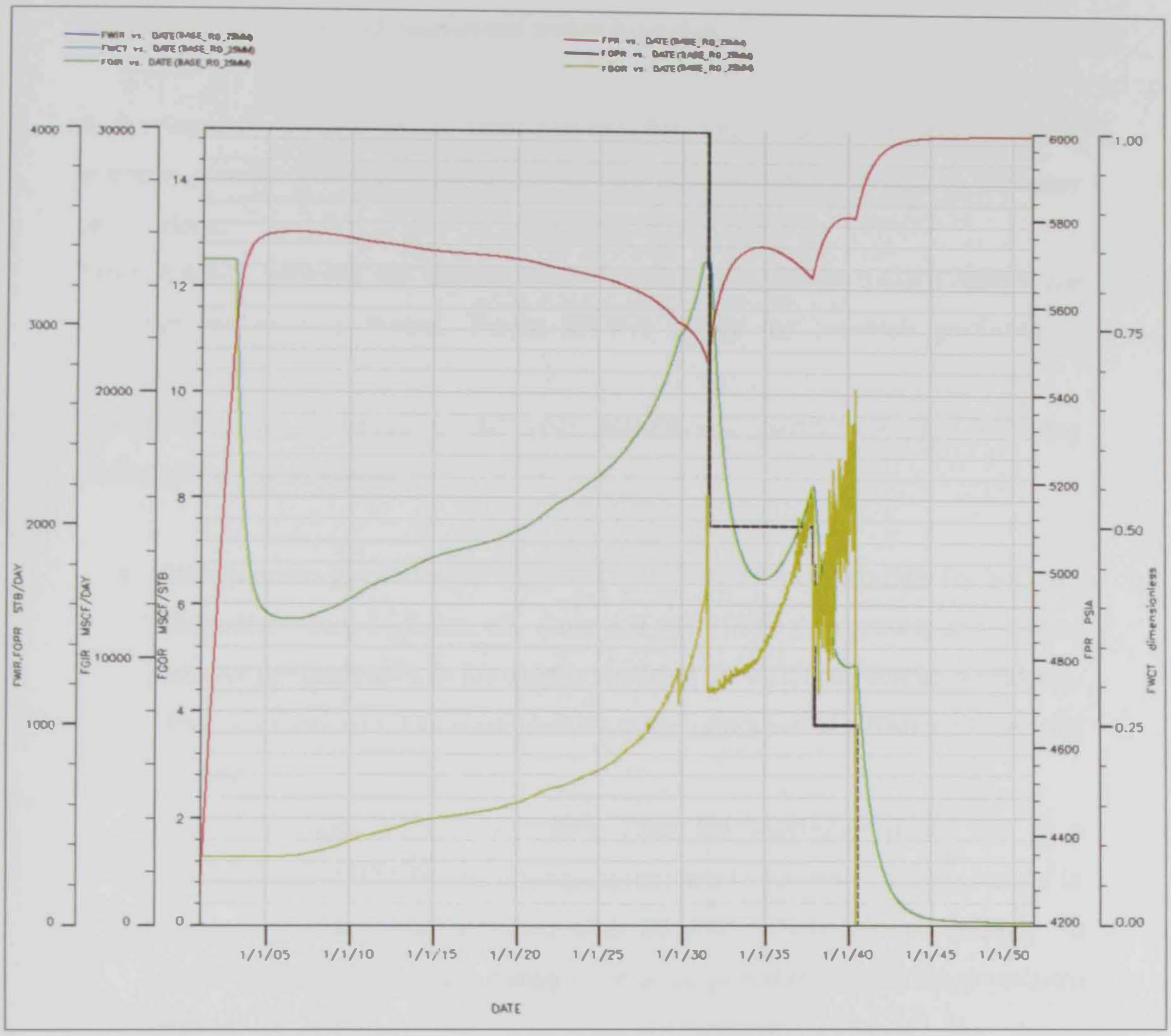

Figure 6.4.1-A: AG / RG continuous injection reservoir performance

6.4.2 AG/RG – gas and co-current water injection

A development option could be identified based on simultaneous AG/RG and water injection process where both gas and water are injected simultaneously in the same perforations.

Table 6.4.2-A presents the development option stated. Table 6.4.2-B shows the reservoir performance results. Figure 6.4.2-A shows the reservoir performance profiles.

Investigating the evolution of different performance parameters, the following findings could be indicated:

- Simultaneous gas and water injection will decrease the injectivity for both gas and water where 3-phases; oil, water and gas will be then present and 3-phase relative permeabilities in the neighborhood of the well bore will be considered. The injectivity could increase later on as the saturation of different phases will change.
- The water injection rate will drop from the maximum initial rate to a maximum of 1000 BBLS/D during approximately one year and then started to increase to reach 3800 BBLS/D after 30 years. There was accordingly no water breakthrough neither during the plateau period not during the drawdown period.
- The gas breakthrough after 7 years and the GOR reached 6 MSCF/STB at the end of the plateau period. It reached the maximum value of 10 MSCF/STB at the end of the drawdown period which is 45 years after the start of production.
- The plateau period achieved was 32 years. The wells were closed because of the high GOR since there was no water production indicated as stated previously.
- The drawdown period was 8 years. This can be extended by relaxing the maximum GOR to a value beyond 10 MSCF/STB.
- The reservoir pressure was built to a maximum value of 5780 psi during a short period and started to decrease after gas breakthrough.

Table 6.4.2-A: Associated / Rich gas water injection development option

Development Scheme		
Area	Middip	
Well Pattern	Direct line drive	
Well Completion	Producers	Lateral
	Injectors	Lateral
Development Process		
Injectant	Upper	-
	Lower	Associated/Rich gas, Water
Reservoir Management		
Water Injection	Upper	-
	Lower	4.0 MSTBD
Oil Production	Upper	0.0 MSTBD
	Lower	4.0 MSTBD
Gas Injection	Upper	0.0 MMSCFD
	Lower	12.5 MMSCF/D
Business Plan		
Phases	One Phase	

Table 6.4.2-B: Associated / Rich gas water injection results

Development Option Results								
Development Option	Field Plateau Production Rate (STB/D)	Field Plateau Gas injection Rate (MMSCF/D)	Field Plateau Water injection Rate (BBLS/D)	Plateau Period (Years)	FOPT (STB)	FGPT (MSCF)	FWPT (BBLS)	URF (%)
AG / RG , WATER	4000	12.5	4000	32	5.2E+7	1.36E9+8	0	59

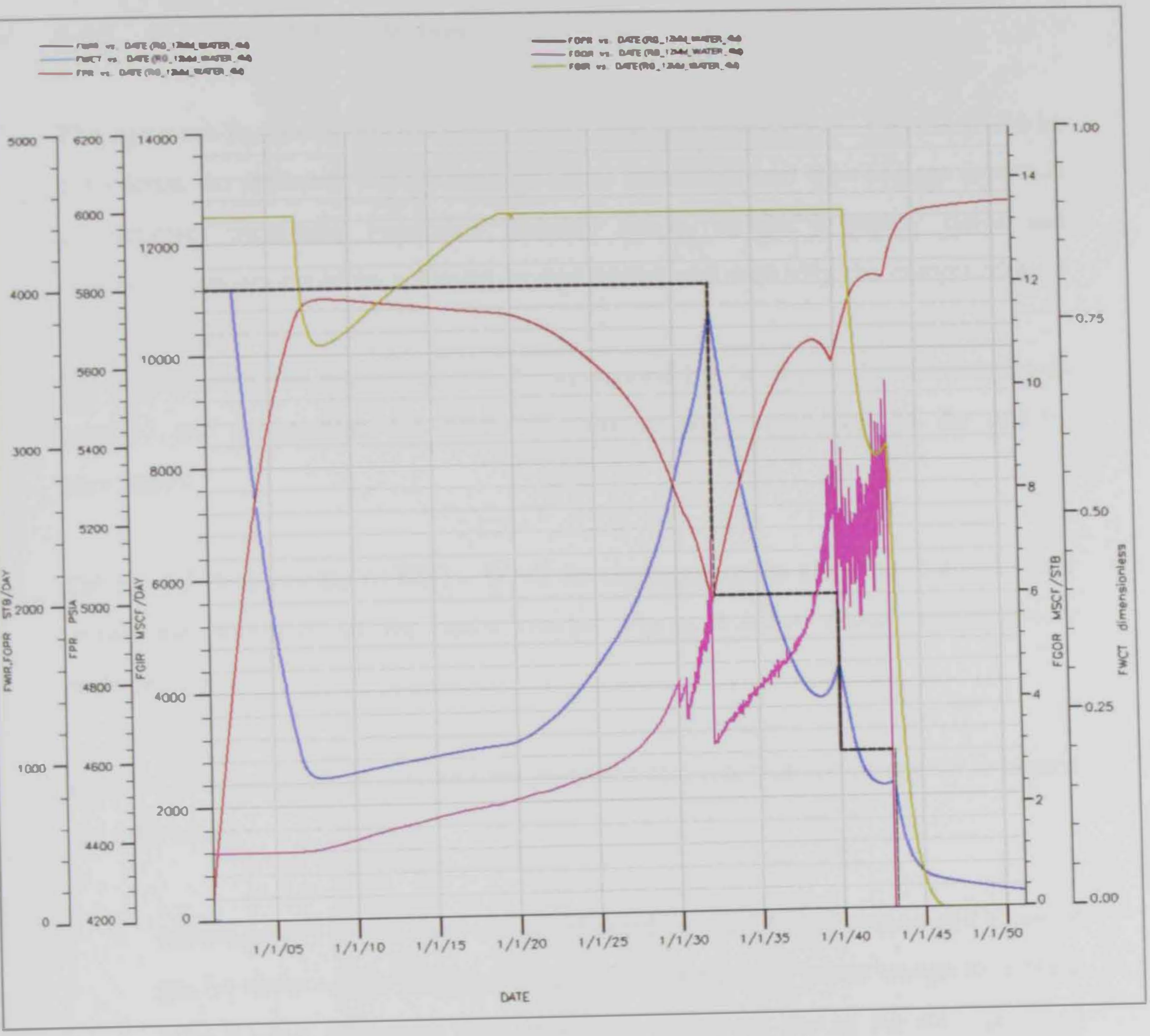

Figure 6.4.2-A: AG/ RG gas-water-co injection reservoir performance

6.4.3 AG /RG – WAG injection

The optimum hydrocarbon rich gas – WAG miscible development process could be considered the reference for all miscible/ near miscible / non miscible gas injection development processes. Favorable mobility ratios, viscous / gravity ratios and capillary numbers could be achieved by optimizing and enriching the composition of the gas.

For this exercise, the composition of the associated gas before gas breakthrough was selected and no attempt was made to optimize the composition of the gas by enrichment.

Table 6.4.3-A shows the AG/RG – WAG development option assessed. Table 6.4.3-B shows the summary of the main results. Figure 6.4.3-A shows the reservoir performance.

Detailed interpretation of the well performance and reservoir performance indicated the following:

- Heterogeneity of the reservoir is reflected by the GOR evolution and times of gas breakthrough in the producing wells. The first gas breakthrough took place after 9 years where the new GOR built up slowly during the subsequent 15 years. A global gas breakthrough took place after 24 years and the GOR then increased steeply.
- The water breakthrough did not take place during the predicted period.
- The plateau rate was maintained for 34 years. The drawdown period was 8 years. The drawdown period could be extended by relaxing the maximum GOR.
- Before gas breakthrough, the reservoir pressure built up to about 5550 psig and then started to decrease after gas breakthrough during the plateau period where it reached 4400 psi.

Table 6.4.3-A: Associated gas/Rich gas – WAG development option

Development Scheme		
Area	Middip	
Well Pattern	Direct line drive	
Well Completion	Producers	Lateral
	Injectors	Lateral
Development Process		
Injectant	Upper Lower	Water, Associated gas / Rich gas
Reservoir Management		
Water Injection	Upper	-
	Lower	8.0 MSTBD
Oil Production	Upper	0.0 MSTBD
	Lower	4.0 MSTBD
Gas Injection	Upper	0.0 MMSCFD
	Lower	25 MMSCF/D
Business Plan		
Phases	One Phase	

Table 6.4.3-B: Associated gas/Rich gas – WAG results

Development Option Results								
Development Option	Field Plateau Production Rate (STB/D)	Field Plateau Gas injection Rate (MMSCF/D)	Field Plateau Water injection Rate (BBLS/D)	Plateau Period (Years)	FOPT (STB)	FGPT (MSCF)	FWPT (BBLS)	URF (%)
AG / RG WAG	4000	25	8000	34	5.3E+7	1.29E+8	0	60

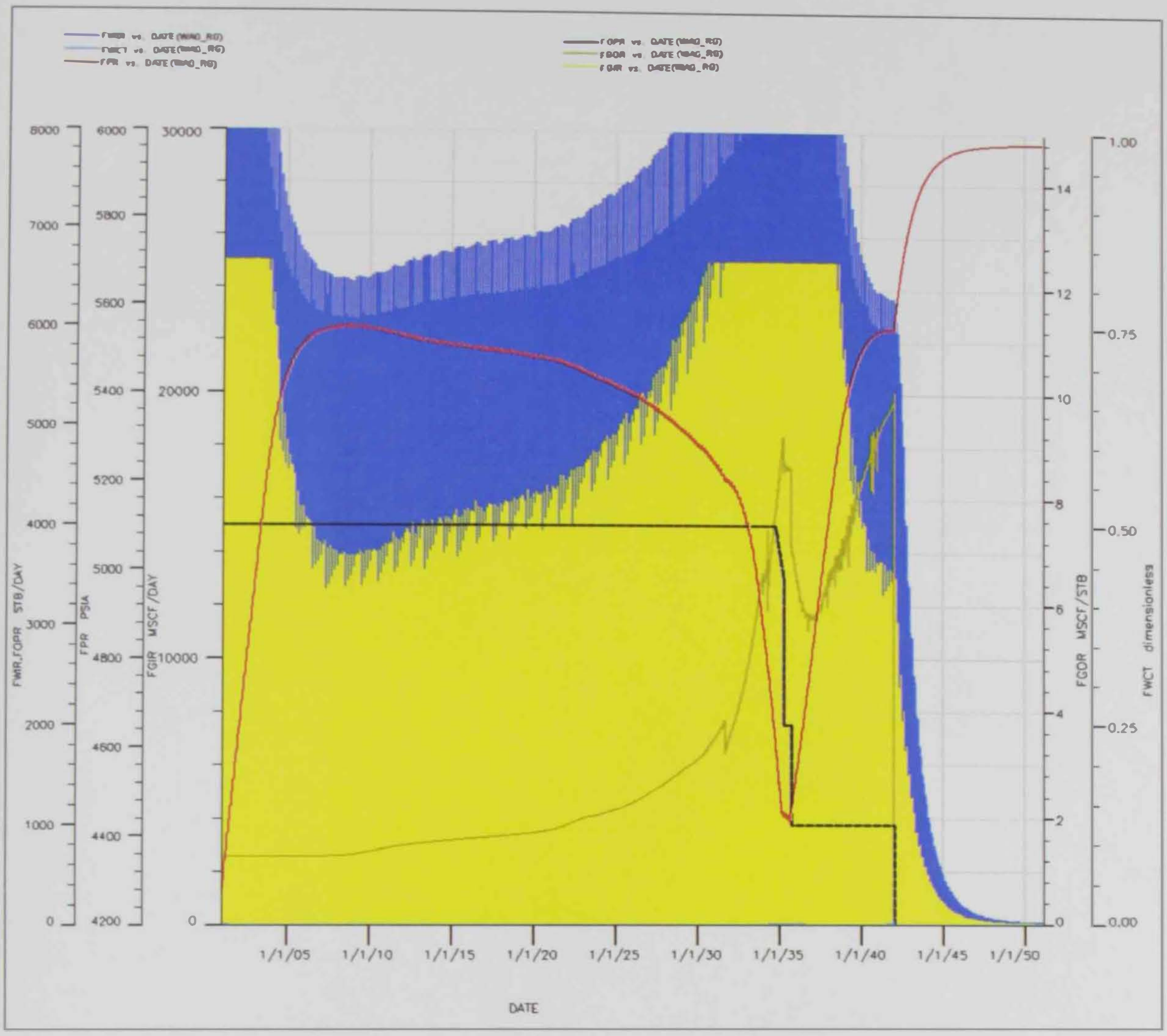

Figure 6.4.3-A: AG /RG – WAG injection reservoir performance

CHAPTER VII

ANALYSIS AND DISCUSSION OF RESULTS

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Identification and assessment of development options were conducted. Selection, definition and execution of the assessed development options are normally conducted where an economical model is applied. The development options were classified and grouped based on the main components of the development options comprising the development scheme, the development process, the reservoir management plan including production-injection profiles and the business plan including implementation and operating plans.

The development options studied were classified based on the EOR development processes. The emphasis will be made on the following:

- H_2S-EOR development process.
- CO_2-EOR development process.
- N_2-EOR development process.
- AG/RG-EOR

Also, the following development options were studied and will be used as base and / or reference cases:

- Water injection development process.
- Lean gas / C_1 injection development process.

The indicated development options can be grouped to be able to compare the production injection profiles and finally the ultimate recovery factor. The following groups / types are adopted:

- Water injection development options.
- Gas injection development options.
- WAG development options.
- SWAG development options.

A water development option will be always referenced and included.

The initial properties of the injectants and reservoir fluid could be summarized in Table 7-B as follows:

Table 7-A: Initial properties of injectants and reservoir fluid

Process	Viscosity ratio (μo / μg) cp/cp	Density difference (ρo - ρg) lbs/ft^3
H_2S	0.18/0.22	38-40
CO_2	0.18/0.06	38-37.8
N_2	0.18/0.0275	38-13.4
AG/RG	0.18/0.023	38-10.8

7.1 Gas injection development process

The gas composition and reservoir pressure and temperature are the main variables that could define the efficiency of any gas injection development process when the gas is a single component, the properties of the gas under reservoir pressure and temperature will define the efficiency of the process. When the gas is a multi component gas the mole percent of individual components should be selected to achieve the designated recovery efficiency. This may lead to gas enrichments if the composition is unfavorable.

Figure 7.1-A presents recovery profiles and Table 7.1-A present recovery factors for different gas injection processes.

Figure 7.1-A: Recovery profiles for different gas injection processes

The recovery factor after 50 years for different processes are listed below:

Table 7.1-A: Recovery factor for different processes

Process	Recovery factor %
H_2S	56.5
CO_2	55.4
N_2	27.1
AG/RG	55.4
H_2O	50.8

To achieve a high recovery factor, the displacing fluid should achieve high areal, vertical and displacement efficiency. This means that viscous to gravity forces ratio R(V/G), the mobility ratio (M), and the viscous to capillary forces ratio, capillary number, the miscibility pressure (MMP) and the technical rate are favorable.

The main variables of the above processes that affect the recovery factors could be summarized as follows:

Process	Results
H_2S	- Increase in oil viscosity - Swelling of the oil - Increase in oil density - Lowering of the interfacial tension. Miscibility with oil is achieved
CO_2	- Reduction in oil viscosity - Swelling of the oil - Minor change in oil density - Lowering of the interfacial tension. Miscibility with oil is achieved.
N_2	- Viscosity ratio >1. - N_2-Oil is immiscible. - Vertical viscous forces is higher than gravity forces. - Capillary number is not high
AG/RG	- Large reduction in oil viscosity. Mobility ratio is most probably less than one. - RG is miscible at reservoir pressure. - Swelling of the oil. - Reduction in oil density.

The recovery of H_2S gas injection process is relatively high due to the following:

- In the neighborhood of the producing well, the miscible conditions are achieved. The mobility ratio is favorable and the viscous to gravity ratio is most probably also favorable leading to relatively good areal and vertical sweep efficiencies.
- In all flooded layers, the areal sweep efficiency is apparently high.

7.2 SWAG injection development process

Injecting gas and water simultaneously in a layered reservoir where gas is injected in the lower low permeable layers and water was also injected in the lower less permeable layers. The fluid flow pattern could be as follows:

- Multiphase flow in the upper high permeability layers.
- Single phase oil, then two phase, oil and gas, after gas breakthrough and finally multiphase flow, oil, gas and water after water breakthrough in the neighborhood of the producers. Of course the time of fluid breakthrough will depend on the type of fluid and composition of gas.

Figure 7.2-A presents recovery profiles and Table 7.2-A presents recovery factors for different SWAG injection processes.

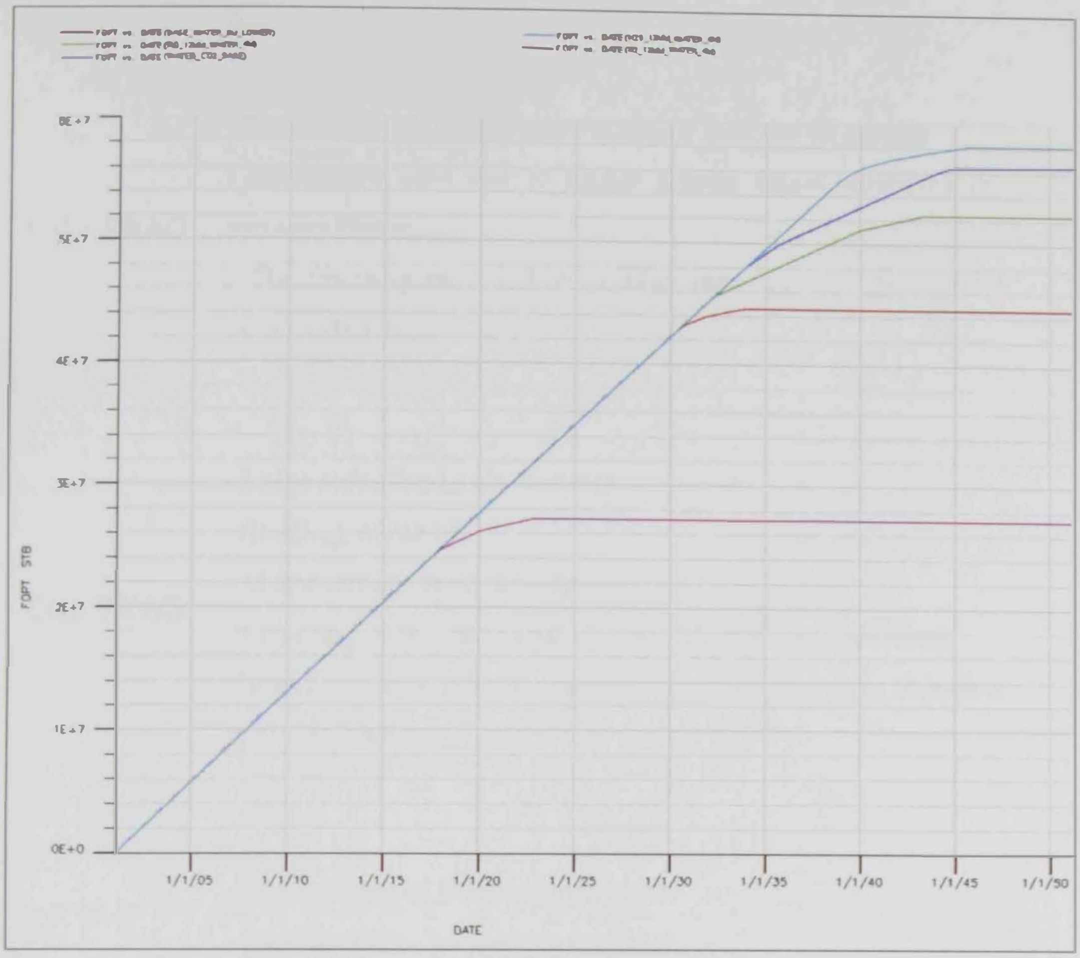

Figure 7.2-A: Recovery profiles for different SWAG injection processes

Table 7.2-A: The recovery factors after 50 years for different SWAG processes

Process	**Recovery factor**
H_2S - SWAG	65.6
CO_2- SWAG	64.5
N_2- SWAG	30.5
AG/RG- SWAG	59
H_2O	50.8

The main variables of these processes that affect the recovery factors of the above processes could be summarized as follows:

Process	Results
H_2S - SWAG	- The density of the injectants is higher than the oil density. - Downward flow due to higher gravity forces improves the recovery factor. - The viscosity ratio and/or mobility ratio improve the vertical sweep efficiency.
CO_2- SWAG	- Large reduction in oil viscosity. - Swelling of the oil - Minor change in oil density - Lowering of the interfacial tension. Miscibility is achieved. - Water viscosity is higher than oil viscosity leading to favorable H_2O-oil mobility.
N_2- SWAG	- The swelling of N_2 is relatively poor. - The miscibility pressure is very high. - Viscous to gravity ratio is unfavorable leading to poor areal sweep efficiency. - Viscosity ratio and most probably mobility ratio are unfavorable leading to poor areal sweep efficiency. - Interfacial tension is relatively high leading to high residual oil saturation.
AG/RG-SWAG	- Override of the injected gas in the area between producers and injectors. - Volumetric sweep efficiency of the lower part is lower. - Recovery increase when the GOR and WC increases and the injected volume increases.

7.3 WAG injection development process

Water alternating gas injection process was found to better optimize the microscopic and macroscopic displacement efficiencies. However, different gases give different recovery factors depending on pertinent mobility ratios, viscous to gravity ratio and viscous to capillary pressure ratio.

The fluid flow for a WAG injection development process in the studied reservoir is a multiphase fluid flow in the neighborhood of the injector, in the high permeability layers and in the neighbor hood of the producers.

The following WAG processes were identified and studied:

- H_2S-WAG development process.
- CO_2-WAG development process.
- N_2-WAG development process.
- AG/RG-WAG development process.

The cycle time of a WAG process could have a big effect on the control of WAG performance process, especially when there is a big heterogeneity and anisotropy in the rock model. It is believed that WAG process will have a better control compared to SWAG process on viscous fingering and viscous override.

Figure 7.3-A presents recovery profiles and Table 7.3-A presents recovery factors for different WAG injection processes.

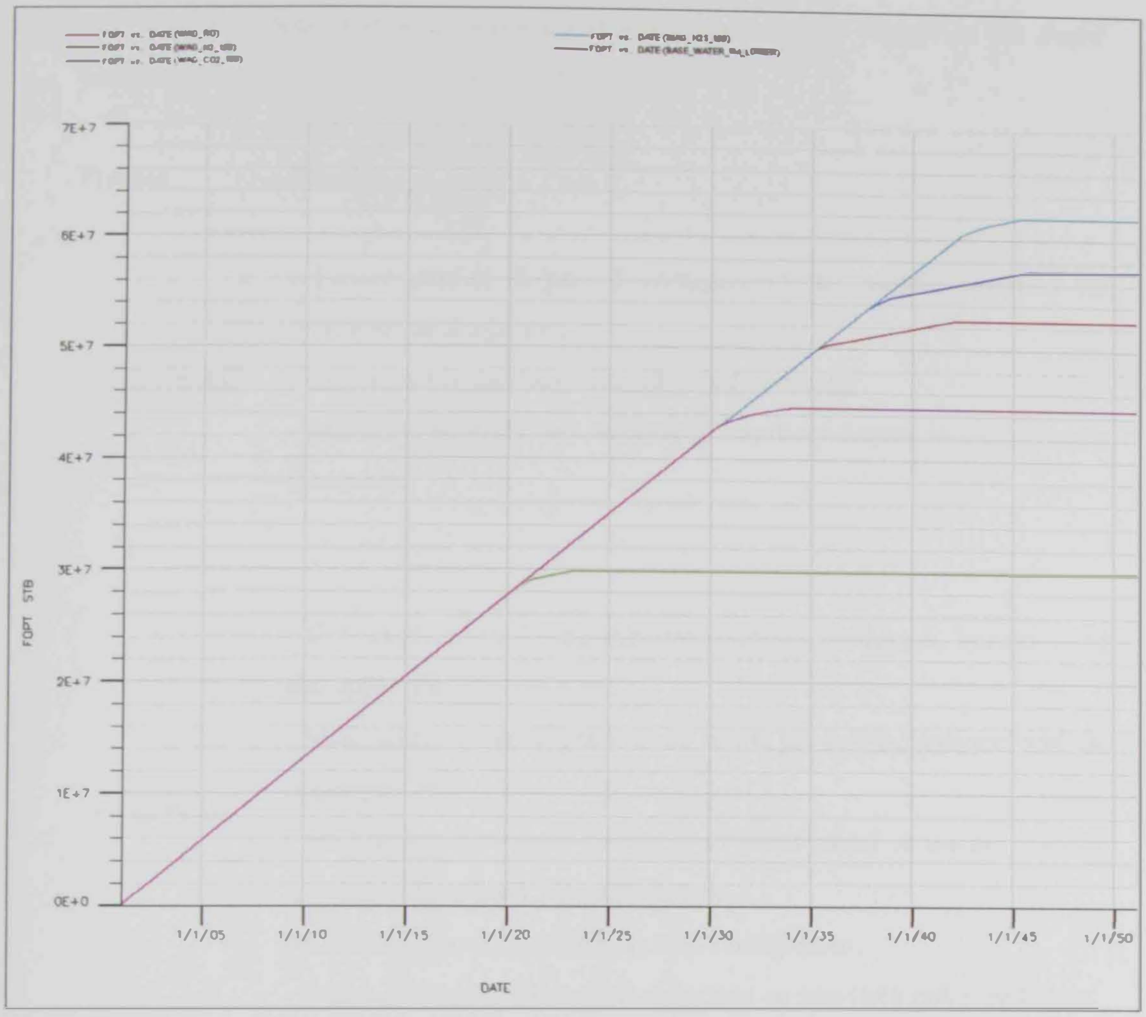

Figure 7.3-A: Recovery profiles for different WAG injection processes

Table 7.3-A: The recovery factors after 50 years for different WAG processes

Process	**Recovery factor %**
H_2S - WAG	70.1
CO_2- WAG	64.5
N_2- WAG	33.9
RG- WAG	60.0
H_2O	50.8

The main variables of these processes that affect the recovery factors of the above processes could be summarized as follows:

Process	Results
H_2S - WAG	- Lower part is displaced vertically in the middle between the producers and injectors. - Upper part is displaced aerially and vertically - Mobility, R(V/G) and viscous to capillary forces ratios are more favorable.
CO_2- WAG	- CO_2 swelling in the neighborhood of the producers, injectors and the upper part. - Miscibility in the neighbor hood of the producers, injectors and the upper part. - Inter region flow from the upper to lower based on the net viscous, gravity and capillary pressure forces. - Effect of viscosity reduction on mobility ratio. - Effect of interfacial tension reduction on capillary pressure forces.
N_2 - WAG	- Poor areal, vertical and displacement efficiency where the process is immiscible. - The microscopic and macroscopic displacement ratios are unfavorable
AG/RG - WAG	- Microscopic and macroscopic functions depend on composition and fluid and rock-fluid properties. - The richness of the gas will theoretically define the recovery.

CHAPTER VIII

CONCLUSIONS

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The results of this study lead to the following conclusions:

- Quality assurance of used models in the optimization study is necessary. This includes integrated reservoir characterization model and matched subsurface reservoir simulation model that may be coupled with surface simulation model and a strategic economical model.
- The optimization of the recovery factor can be achieved by optimization of the full field development options.
- The main components of the field development options are development scheme, development process, production – injection plan / profile, business / execution plan and operating / reservoir management plan.
- All variables of the micro displacement and macro displacement efficiencies should be investigated as dependent variables for the ultimate recovery factor or the independent variable.
- A recovery factor of more than 70 % could be achieved by H_2S-WAG injection process, where the process is miscible, the mobility ratio is favorable, and the viscous / gravity ratio is mostly favorable.
- A recovery factor of more than 60 % could be achieved by enriched hydrocarbon gas injection process where the process is miscible, the mobility ratio is favorable, and the viscous / gravity ratio is mostly favorable.
- A recovery factor of 60 % - 70 % could be achieved by CO_2-WAG injection process where the process is miscible at high reservoir pressure. The mobility ratio is favorable and the viscous / gravity ratio is mostly favorable.
- A recovery factor of 50 % - 60 % could be achieved by LHGI-WAG process where it is first multi contact miscible. The mobility and the viscous / gravity ratios will be less favorable.
- A recovery factor of 40 % - 50 % could be achieved by C_1-WAG gas injection process, where the process is mostly immiscible. The mobility and the viscous gravity ratios will be less favorable.

- A recovery factor of less than 40 % could be achieved by N_2-WAG gas injection process where the process is immiscible and the fluid flow forces ratios are mostly unfavorable.
- A recovery factor of approximately 50 % could be achieved by water injection where the fluid flow forces ratios are mostly favorable and the micro displacement efficiency is relatively low or the residual oil saturation is high.
- The development scheme is strongly dependant on reservoir heterogeneity (rock model) and fluid heterogeneity (fluid model) as well as the production-injection profile (business plan).
- The development phases are strongly dependent on reservoir performance and reservoir management together with reservoir development strategy.
- The technical constraints could be identified, assessed and selected independently. Integrated optimization studies could be then conducted to select the optimum development option.
- A recovery factor of 75 % could be recommended as a target recovery factor for any reservoir development optimization study.

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إسم الباحث

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